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16. ABSTRACT The proceedings document presentations at the 1989 Joint Symposium on Stationary Combustion NOx Control, held March 6-9, 1989, in San Francisco, CA. The symposium, sponsored by the U.S. EPA and EPRI, was the fifth in a series devoted solely to the discussion of control of NOx emissions from stationary sources. Topics discussed included low-NOx combustion developments such as burner design modifications and reburning; coal-, oil-, and gas-fired boiler applications; flue gas treatment processes; fundamental combustion studies; and industrial and commercial applications. Also presented were manufacturers' updates of commercially available technology and an overview of environmental issues involving NOx control. The 4-day meeting was attended by persons from 14 nations. More than 50 papers were presented by EPA and EPRI staff members, utility company representatives, boiler and related equipment manufacturers, research and development groups, and university representatives. The proceedings are in two volumes. Volume 1 includes background, combustion NOx developments I and II, manufacturer's update, advanced combustion technology, and incineration. Volume 2 includes SCR coal applications, fundamental combustion research, post combustion NOx control development, fundamental combustion research, new developments, and oil and gas combustion.

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San Francisco, CA, March 6-9, 1989
Volume 1

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ABSTRACT

The 1989 Joint Symposium on Stationary Combustion NO_x Control was held in San Francisco, California, March 6-9, 1989. This Symposium, jointly sponsored by EPRI and EPA, had as its objective the exchange of information regarding recent technological and regulatory developments pertaining to stationary combustion NO_x control in the United States and abroad. Topics covered during the Symposium included: low-NO_x combustion development; coal-, oil-, and gas-fired boiler applications; flue gas treatment; fundamental combustion studies; and environmental and regulatory issues. The Symposium Proceedings is published in two volumes.

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

PREFACE

The 1989 Joint Symposium on Stationary Combustion NO_x Control was held March 6-9, 1989, in San Francisco, California. This symposium, jointly sponsored by EPRI and EPA, was the fifth of its kind devoted solely to the discussion of control of NO_x emissions from stationary sources. Specific topics discussed included the low-NO_x combustion developments such as burner design modifications and reburning, coal-, oil-, and gas-fired boilers applications, flue gas treatment processes, fundamental combustion studies, and industrial and commercial applications. Also presented were manufacturers' updates of commercially available technology and an overview of environmental issues involving NO_x control.

The four-day meeting was attended by persons from 14 nations. Over fifty papers were presented by EPRI and EPA staff members, utility company representatives, boiler and related equipment manufacturers, research and development groups, and university representatives.

Symposium cochairpersons were David Eskinazi, Project Manager in the Air Quality Control Program of EPRI's Generation and Storage Division; and Dr. William P. Linak, Chemical Engineer in the Combustion Research Branch of the EPA's Air and Energy Engineering Research Laboratory. Each of the cochairpersons made brief introductory remarks. Mr. David Finnigan, Counsel for the House Energy and Commerce Committee delivered the keynote address. Written manuscripts were not prepared for the introductory remarks or keynote address; therefore, they are not published herein.

The Proceedings of the 1989 Joint Symposium have been compiled in two volumes. Volume 1 contains papers from the following sessions:

- Session 1: Background
- Session 2: Combustion NO_x Developments I
- Session 3: Combustion NO_x Development II
- Session 4: Manufacturer's Update
- Session 5A: Advanced Combustion Technology
- Session 5B: Incineration

Papers from the following sessions are contained in Volume 2:

- Session 6A: SCR Coal Applications
- Session 6B: Fundamental Combustion Research
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INNOVATIVE CLEAN COAL TECHNOLOGY NO_x CONTROL TECHNOLOGY

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ABSTRACT

The recent selections of the Innovative Clean Coal Technology program were made on September 27, 1988, and consisted of 16 projects. A number of the projects involved techniques for controlling NO_x–i.e., from coal-fired power plants. These projects will be described in detail.

Three of the projects represent innovative combustion control techniques and one involves catalytic reduction. In addition, five of the selected projects involve a combination of SO_2 and NO_x control -- two employ flue gas cleanup techniques and three employ repowering techniques.

INNOVATIVE CLEAN COAL TECHNOLOGY NO_x TECHNOLOGIES

As a result of the recent Innovative Clean Coal Technology Solicitation, 16 projects, valued at more than $1.3 billion, were selected to demonstrate advanced technologies for controlling SO_2 and NO_x emissions in existing coal-fired plants. The solicitation is part of the commitment made by President Reagan in March 1987 for a $5.0 billion program of which the Federal Government would contribute $2.5 billion to demonstrate improved techniques that could be used in the 1990's to reduce pollutants from existing coal-fired plants that are commonly associated with acid rain. The projects comprise a wide variety of SO_2 and NO_x control techniques. Ten of the 16 projects involve NO_x control techniques. Of these, seven will demonstrate retrofit technologies which modify existing facilities to reduce emissions. The remaining three projects will demonstrate repowering technologies which replace a significant portion of the original facility and, in addition to achieving significant emission reductions, often increase capacity, extend the life of the plant, and improve efficiency of the system.

Brief descriptions of the ten projects involving NO_x control are provided.

Retrofit Technologies:

Three of the seven NO_x control projects selected for demonstration of retrofit technologies were proposed by Southern Company Services (SCS), Inc., of Birmingham, Alabama. They comprise advanced wall-fired combustion techniques, advanced tangentially-fired combustion techniques, and selective catalytic reduction (SCR) technology.

SCS Low NOx-Wall Fired

SCS plans to demonstrate the long-term optimal cost/performance potential of several NO_x control techniques used both alone and in combination in a single boiler. The NO_x control technologies used in these projects will be characterized by comparing long-term pre-retrofit data with long-term post-retrofit data. Sufficient data is to be generated to allow extrapolation to the general boiler population through the use of statistical techniques. The SCS project is intended to supplement previous short-term evaluations by burner manufacturers to show the NO_x reduction potential of their equipment. However, these short-term evaluations have not generated sufficient data to extrapolate to the general population of boilers. The dynamic requirements of utility boiler operations usually diminish the actual NO_x reduction achieved in short-term evaluation since some additional margin is required to avoid periodic upsets (slagging, high convective pass temperatures, etc.).

The majority of electric utility coal-fired boilers in the United States are either wall-fired or tangentially (corner)-fired. Each class of boiler has a characteristic range of NO_x emissions that derives from these different configurations.

NO_x control technologies to be evaluated for wall-fired boilers will consist of advanced overfire air (AOFA) and Low-NO_x burners both singularly and in combination. In conventional Over Fired Air (OFA) configurations, some of the combustion air is diverted away from the burners driving the stoichiometry of the burner toward a fuel-rich condition; the diverted air is supplied above the combustion zone to complete combustion before the combustion products reach the convective pass of the furnace. However, standard OFA designs do not obtain complete mixing of the partially combusted gases above the burners. AOFA incorporates injection port and duct configurations (sometimes in combination with booster fans) of aerodynamic design to provide superior mixing of the partially combusted fuel and air to achieve more complete combustion and enhance NO_x reduction performance. AOFA is expected to achieve about 35 percent NO_x reduction.

The concept of overfire air was conceived by Babcock & Wilcox (B&W) in the 1950's for application on gas- and oil-fired boilers in Southern California to meet stringent NO_x regulations, and has been used on utility boilers in response to the 1971 NSPS standards. Although OFA techniques have been effective in NO_x reduction, problems have been associated with their use in coal-fired boilers. These problems have been associated with poor overfire air mixing, which caused reducing environments within the furnace and flame carryover into the convective pass (both conditions responsible for corrosion problems with the boiler tubes). To counteract this problem some of the combustion air can be diverted along the walls creating an oxidizing boundary layer across the boiler tubes. Although most manufacturers have recognized this shortcoming and are redesigning their OFA ports and ducts, such AOFA techniques have not been applied to a full-scale boiler.

The new Low-NO_x burner systems for coal employ a technique of separating the fuel and air streams in the primary combustion zone. The complete systems also incorporate the standard OFA configuration.

Older Low-NO_x burner designs utilized turbulent burners to combust the pulverized coal causing a significant portion of the fuel-bound nitrogen to be converted to NO_x. The new Low-NO_x burner systems incorporate burners that inject the fuel and air in a manner that prevents turbulent mixing during the initial combustion. This localized staged combustion allows for devolatization of the fuel-bound nitrogen in an initial reducing atmosphere converting a significant portion of the fuel-bound nitrogen to N_2 with no further oxidation to NO_x. In properly designed burners, short-term reductions in the range of 40 to 50 percent have been achieved. The SCS demonstration will evaluate three commercial prototype LNB designs--B&W DRB (Dual Register Burner)-type XCL burner with impeller, Foster Wheeler CFSF (Controlled Flow/Split Flame) burner, and Riley Stoker CCV (Controlled Combustion Venturi) burner--to determine which one is most suitable for this application.

The combination of AOFA and Low NO_x Burner (LNB) is expected to achieve about 60 percent reduction in NO_x emissions.

The demonstration of wall-fired combustion technologies is planned at the 500 MW Unit 4 of Georgia Power Company's Plant Hammond near Rome, Georgia. This unit is representative of a large class of wall-fired boilers accounting for 35 percent of the 1985 capacity of all pre-1979 NSPS boilers (boilers without FGD units and mostly without NO_x control devices) for 411 out of a total of 929 boilers in this group. The 411 boilers produced about 35 percent of the total 1985 NO_x emissions of 4.9 million tons for the 929 boilers.

SCS Low NOx--Tangential Fired

The SCS program to demonstrate Low-NO_x technologies for tangentially-fired boilers will encompass three techniques: AOFA, Low-NO_x Concentric Firing System (LNCFS), and an Advanced Tangential Firing System (ATFS). The AOFA configuration is similar to that described for the wall-fired boiler. The application of LNCFS encompasses a modification to the conventional tangential firing configuration which results in stabilizing the flame front and allows the initial devolatization period to occur within a fuel-rich atmosphere. The ATFS is a proprietary configuration and cannot be described here. Based on short-term parametric testing the AOFA is expected to achieve 25 - 35 percent NO_x reduction while LNCFS and ATFS are each expected to achieve 35 - 45 percent reduction. The combination of ATFS and AOFA is expected to achieve 50 - 60 percent NO_x reduction based on the same short-term data.

The demonstration of tangentially-fired combustion technologies is planned at the 180 MW Unit 2 of Gulf Power Company's Plant Smith in Lynn Haven, Florida near Panama City. This unit is a Combustion Engineering corner-fired steam generator. Tangentially-fired boilers account for 42 percent of the 1985 capacity of all pre-1979 NSPS boilers for 345 out of a total of 929 boilers in this group. The 345 boilers produced 34 percent of the total 1985 NO_x emissions of 4.9 million tons for the 929 boilers.

Because of the effect that Low-NO_x techniques have on furnace stoichiometry, demonstration plans for both wall- and tangentially-fired combustion technologies call for careful monitoring of particulate, sulfur oxide, hydrocarbon emissions, and furnace wall corrosion. Particulate emissions can be significantly affected by the use of Low-NO_x techniques especially with ESP units because of the increase in carbonaceous particles due to incomplete combustion products, increased particle size, and change in particle resistivity.

SCS-SCR Technology

SCS recently conducted an extensive evaluation of commercial or near-commercial post-combustion NO_x control processes using information supplied by more than forty organizations worldwide. Selective Catalytic Reduction (SCR) was selected for further evaluation because it is the most technically mature of the available processes. Nevertheless, significant uncertainties remain about SCR design, performance, and cost when applied to high-sulfur United States coal and the more variable load demand under which U.S. electric power plants operate compared to those in Japan where there has been widespread commercial use of SCR technology. SCR has the advantage, compared to combustion modification NO_x reduction approaches as described above, of being applicable to every type of boiler, and can achieve up to 90 percent NO_x emission reduction.

The SCR process consists of reacting ammonia with the NO_x in the flue gas prior to the preheater in the presence of a catalyst to form nitrogen and water. Because it is necessary to ensure a minimum temperature to the SCR unit, it is necessary to provide a bypass around the economizer at rear of the furnace which may have a negative effect on overall thermal efficiency of the boiler. Also, any excess ammonia will react with the sulfur trioxide, which forms as a result of the oxidation of sulfur dioxide in the presence of the catalyst, yielding ammonia hydrosulfate. Ammonia hydrosulfate can corrode the metal of the air preheater and trap flyash causing decreased heat transfer performance and increased pressure loss. All of these potential problems associated with SCR usage in U.S. electric plants will be investigated in the SCS SCR project to determine design, cost, and operating parameters that may mitigate these concerns. In order to address these uncertainties, a multiple unit SCR prototype demonstration is planned between units 5 (75MW) and 6 (320 MW) of Gulf Power Company's Plant Crist near Pensacola, Florida. This location allows access to flue gas from approximately three percent sulfur coal under a variety of different NO_x and particulate levels.

The prototype demonstration plant will include three SCR/air preheater trains with 2½ MW flue gas flow each. These reactors will be used to evaluate current commercial catalyst offerings. Six smaller test units (0.05 MW each) will be included to increase the flexibility of the commercial catalyst testing and to allow testing of advanced catalyst formulations. These prototype demonstration units are being proposed as the most cost-effective approach to SCR evaluation. Larger test units are not believed to be necessary because the major technical issues to be resolved with SCR in the United States are related to the chemical effects of high-sulfur coal flue gas and fly ash upon catalyst life and performance and not to the size of the SCR installation.

CE-WSA/SNOx

The SCR process in combination with a SO_2 catalytic reduction process is for a demonstration project proposed by Combustion Engineering, Inc., (CE) in a joint venture with Snamprogetti USA, Inc., a part of ENI, the Italian National Energy Company. The combined process is known as WSA-SNOX technology and is planned for demonstration on the flue gas from Ohio Edison Niles Station Boiler No. 2 located in Niles, Ohio. The quantity of flue gas that will be processed is equivalent to 35 MW of electric generation. The WSA-SNOX Process is designed to remove at least 90 percent of NO_x emissions.

The WSA-SNOX process is capable of achieving higher NO_x reduction than a stand-alone SCR process because much of the unreacted ammonia, known as "NH_3 slip", is oxidized to nitrogen oxides and nitrogen in the subsequent SO_2 catalytic reactor. There are no limitations as to the type of boiler to which the WSA-SNOX process is applicable.

B&W - SOx/NOx/ROx/ Box

Another combined SO_2/NO_x emissions control process has been proposed by the Babcock & Wilcox Company of Alliance, Ohio. Its SOX-NOX-ROX Box (SNRB) process also accomplishes NO_x reduction through the use of the basic SCR process -- reaction with ammonia in the presence of a catalyst -- to achieve 90 percent NO_x reduction. The simultaneous reduction of SO_2, NO_x, and particulates takes place in a single unit, a hot temperature baghouse. One of the advantages of using the SNRB process is that it recovers the heats of reaction of the pollutant reduction process, resulting in less derating than other types of emission control devices.

A 5MW demonstration project of the SNRB process is planned at Ohio Edison Company's R.E. Burger Station, Unit No. 5, in Dilles Bottom, Ohio. As with the WSA-SNOX process, the SNRB process is expected to be applicable to all boiler configurations.

B&W-Coal Reburning for Cyclone Boilers

Babcock & Wilcox has also proposed NO_x control systems for cyclone boilers for which B&W has been the exclusive supplier to the electric utility industry. Although cyclone boilers have the advantages of burning lower grade coals, allowing for the use of crushed coal and thus requiring less coal handling equipment, creating less fly ash in the flue gas, and reducing total boiler size compared to other PC boilers; they produce greatly increased turbulence in the primary combustion zone which causes increased NO_x formation. Coal-fired cyclone boilers make up 9 percent of the pre-1979 NSPS capacity but contribute to 15 percent of the 1985 NO_x emissions from these units. This increased turbulence prevents use of delayed or staged Low-NO_x combustion systems with cyclone boilers due to the corrosive effect on furnace walls. However, reburning with a supplementary fuel in a reducing atmosphere above the primary combustion zone results in converting much of the NO_x in the combustion gases to molecular nitrogen and carbon monoxide. To complete the combustion process, a third combustion zone is created through the use of OFA ports. Although fuels used for reburning have been oil or gas, the B&W proposal plans to use ultra-fine pulverized coal as the reburning fuel. The proposed reburning will use the same coal that is fed to the cyclone burners, thus eliminating (1) the need to access an alternative premium fuel, which may not be available, and (2) the associated expenses of purchasing, handling and burning the alternative fuel.

B&W plans to demonstrate reburning technology at Wisconsin Power & Light Company's Nelson Dewey Station Unit No. 2, located at Cassville, Wisconsin. This unit is a 100 MW boiler equipped with three cyclone burners and is representative of the majority of cyclone burners currently in operation.

Transalta Low NOx/SOx Combustor

Transalta Resources Investment Corporation of Calgary, Alberta, Canada has proposed another technology for NO_x control in Cyclone Boilers, through retrofit of the Low SO_x/NO_x (LNS) Burner. The LNS burner is designed to release all of the NO_x and the precursors of NO_x into the gas stream where it is converted to molecular nitrogen. The NO_x removal efficiency of the LNS burner is expected to be about 90 percent removal, comparable to SCR removal rates but at a fraction of the cost. The hot gas stream exiting the LNS burner contains hydrogen, carbon monoxide and a small amount of unburned carbon. Completion of the combustion process takes place with the use of OFA downstream of the burner. Throughout the process, techniques are used to minimize the formation of thermal NO_x.

Demonstration of the LNS burner is planned on the 33MW Unit 1 cyclone boiler of Southern Illinois Power Cooperative near Marion, Illinois. The boiler will be retrofitted with a coal pulverizer system and two LNS burners.

Repowering Technologies:

Repowering technologies comprise two major categories -- fluidized bed combustion and gasification. Both types of repowering are often designed as combined cycle units where the combustion gases can be used to run a gas turbine. The remaining heat of combustion can be used to produce steam for the existing steam cycle. In this combined cycle mode the original power output of the original boiler is typically increased anywhere from 30 to 300 percent resulting in lower cost of electricity compared to single cycle systems. An additional benefit of repowering is life extension of the current plant.

In a fluidized bed a stream of air flows upward through a mass of granular particles. Given sufficient air velocity, the particles are suspended in a highly turbulent suspended state. When a small amount of coal is introduced into the bed, it burns very efficiently and at a much lower temperature, 1600°F bed temperature, than in a pulverized coal boiler (above 2800°F). The lower temperature is sufficient to sustain combustion but is below the ash fusion temperature. The lower temperature also results in virtually eliminating thermal NO_x formation. In addition it widely believed that the majority of the fuel bound NO_x is converted to molecular nitrogen by the catalytic role played by the calcium compounds suspended along with the coal in the fluidized bed. (The calcium is derived from sorbents -- either limestone or dolomite -- added to the bed to capture the sulfur in the coal.) A fluidized boiler typically emits about 0.3 pounds or less of NO_x per million Btu.

Fluidized bed combustion systems are designed to operate either at atmospheric or elevated pressure. Atmospheric fluidized bed combustion (AFBC) is configured either as a bubbling bed or as a circulating fluidized bed (CFB). In a CFB coal, air and sorbent are injected into the fluidized bed to create a primary combustion zone. Combustion is further enhanced by a secondary combustion zone above the bed in which additional air is introduced. This staged combustion contributes to NO_x reduction as described earlier in this paper. Combustion gases and unburned coal particles flow into an adjacent cyclone separator resulting in unburned solids being recirculated to the fluidized bed. This design contributes to more efficient combustion of the coal, a less complex feed system, and lower amounts of sorbent usage than a bubbling fluidized bed boiler.

SPS-CFB

Southwestern Public Service Company (SPS) of Amarillo, Texas, an electric utility, is proposing to demonstrate a CFB repowering of the 250 MW unit NO. 3 at SPS's Nichols Station near Amarillo. The current PC boiler will be completely replaced with a CFB boiler. This is twice as large as the largest CFB currently under construction.

AEP-PFB

A pressurized fluidized bed (PFB), where combustion typically takes place at 10-15 atmospheres, can produce sufficient combustion gases to drive a gas turbine as well as produce high quality steam for the unit's existing steam cycle. Demonstration of repowering with such a combined cycle system has been proposed by American Electric Power Service Corporation, part of the American Electric Power Company (AEP) -- one of the Nation's largest utilities. Plans are for the project to take place in Units 3 and 4 of AEP's Philip Sporn Plant in New Haven, West Virginia. The Philip Sporn Plant is over 35 years old and the repowering is intended to extend its life at least another 30 years. After the units are repowered with PFBC, net electrical generation capability will be about 330 MW for the two units. Each unit is currently rated at 150 MW.

In the repowering of an existing boiler with integrated gasification combined cycle (IGCC), the existing boiler is typically supplemented or replaced by gasifiers which supply cleaned fuel gas to a combustor which drives a gas turbine creating additional electric power capacity. Waste heat from the combustion turbine exhaust gas stream is used to produce high quality steam, using a heat recovery steam generator, to run the existing steam cycle. An IGCC can be designed to achieve a more efficient heat cycle than a PC unit resulting in a significant savings in the cost of electricity. One of the advantages of IGCC systems is that they are modular in design and the capacity of the existing unit can be increased as it is needed.

Very low NO_x levels (0.1 pound per million Btu or better) are achieved with an IGCC because of high removal of the fuel-bound nitrogen in the coal and lower combustion temperatures preventing the formation of thermal NO_x. Partial combustion in the gasifier is taking place in a reducing atmosphere where intermediate combustion products of the fuel-bound nitrogen -- hydrogen cyanide and ammonia - - are produced. (No formation of thermal NO_x takes place which requires an oxidizing atmosphere.) These intermediate products are removed in the gas cleanup system downstream of the gasifier. Formation of thermal NO_x is inherently lower than in PC boilers and is minimized in the gas turbine combustor by combining the fuel gas with water to reduce combustion temperature.

CE-IGCC

Combustion Engineering, Inc., is proposing to demonstrate a coal gasification system to power a gas turbine coupled to a heat recovery steam generator to provide steam to the existing steam cycle. The repowered system will add an additional 40 MW to the system resulting in a doubling of existing capacity. A novel hot gas cleanup system will be employed in parallel with cold gas cleanup.

Conclusion:

The projects selected by DOE in its second Clean Coal solicitation include a wide range of promising NO_x control technologies. The adoption by the industry of those projects that are successfully demonstrated for commercial application will depend on a number of unique individual factors the industry may need to consider (e.g., regulation, site specifics). However, the projects represent a suite of potentially cost-effective advanced techniques for controlling NO_x in existing coal-fired facilities.

The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

POLICIES FOR NOx CONTROL IN EUROPE

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ABSTRACT

Over the last two years, there have been significant developments in NO_x control legislation and policies in Europe. The key factor driving these changes has been concern about the impacts of NO_x emissions on forests, in conjunction with other acidic pollutants and with ozone. Combustion of fossil fuels is the main source of man-made NO_x, with vehicles producing the majority of emissions. Nevertheless, most legislation adopted so far relates to stationary sources.

At international level, agreement has been reached on a NO_x protocol to the UN Convention on Long-Range Transboundary Air Pollution, whilst the European Communities have now adopted emission standards for NO_x from new combustion plants over 50 MWt, and targets for reduction of NO_x emissions from existing large combustion plants.

Nearly all western European countries have now, or plan by 1990 to regulate emissions of NO_x from both new and existing combustion plants.

Policies for control of NO_x emissions vary. Germany is completing a major programme of Selective Catalytic Reduction (SCR) retrofits, and this is also the favoured technology in Austria. Denmark, Finland, the Netherlands and Sweden are investigating the use of SCR and Selective Non-Catalytic Reduction (SNCR) for larger combustion plants. Other countries are focussing on the use of combustion modification approaches. By 1990, there will be around 140 flue gas treatment plants installed in Europe.

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INTRODUCTION

The importance of the role of nitrogen oxides in acidification, forest damage and other environmental problems has received increased attention in recent years in Europe. In the 1970s, long-range airborne transport of sulphur compounds seemed to be the main problem, with surface water acidification the major environmental impact. More recently, as the range of recorded environmental effects has widened to include damage to forests and other vegetation, groundwater, building materials (including historic monuments) and human health, concern has widened to encompass additionally nitrogen compounds, hydrocarbons, ozone and heavy metals. Nitrogen oxide emissions from human activities are key components in the acidic deposition and photochemical oxidation issues. More specifically nitrogen compounds have been shown to take part in long-range (>110 km) transport of acidic gases and aerosols. They are one of the major causal factors in the formation and transport of ozone and other oxidants on a regional scale across Europe.

THE BACKGROUND AND HISTORY OF EUROPEAN POLICY ON NO_x CONTROL

The first scientific observations on which present-day knowledge of acidification is based were made as early as 1947, when a Swedish researcher began systematically to measure the chemical composition of precipitation at ground level. This system was developed further and in 1956 the European Air Chemistry Network was set up including about 100 stations. Continuing research established a link between the increasing acidification of surface waters in Norway and Sweden and long range transport of pollutants. The UN conference on the Human Environment in Stockholm, 1972, was the first time long range transboundary air pollutants received broad political attention. A principal was adopted that States have a responsibility to ensure that energy production and other activities within their territory are not carried out in a way which harms the environment or population of the other states. This principle was enshrined in the 1979 UN Convention on Long Range Transboundary Air Pollution, and a protocol to this convention signed in 1985 committed signatories to reduce their SO_2 emissions by 30% (2).

Work also started in the Organisation for Economic Cooperation and Development (OECD) on a programme to measure the long range transport of air pollutants (LRTAP). The work on LRTAP between 1972-1977 focussed on sulphur dioxide emissions.

In the late 1970s, the first reports were received of damage to forests in Germany associated with air pollution. Research began to indicate that NO_x and other pollutants, as well as SO_2, might be implicated in forest damage. Faced with considerable political pressure from the growing influence of the Green Party, the German government introduced stringent emission standards for both SO_2 and NO_x. In order to prevent competitive disadvantages for German industry, proposals were made for similar legislation to be adopted by the European Communities.

Concern about the impact of NO_x grew and a number of different organisations have started to work on the subject. In 1985 the Nordic Council of Ministers initiated a project called "Critical Loads of Sulphur and Nitrogen", designed to assess the maximum deposition of pollutants which could be tolerated without harm to the environment. Under the UN Convention on Long Range Transboundary Air Pollution a group for NO_x was set up. In 1988 agreements were made in both the EC and the United Nations on controlling NO_x emissions.

The majority of European states now accept that air pollution and the damage it causes are perhaps the most serious environmental problem facing Europe as a whole. It has taken considerable research and political effort to reach this point. For 20 years there have been complex interactions, nationally and internationally, between politicians and scientists. This has also involved a growing number of ordinary people and environmental groups, as awareness of environmental issues and concern about their impacts has grown. Green issues have become increasingly important in European politics, with Green parties gaining parliamentary seats in Germany, Sweden, Belgium, Italy and the Netherlands. Pressures for stricter control of atmospheric pollutant including NO_x, remain strong.

PHILOSOPHIES FOR SETTING EMISSION LIMITS

Over the last two years, there have been significant developments in NO_x control legislation in Europe, both nationally and internationally. Nearly all western European countries now have, or plan to introduce by 1990, regulations on emissions from both new and existing plants (1). Most western European countries have adopted targets for a reduction of total NO_x emissions. Combustion of fossil fuels is the main source of man-made NO_x, with vehicles producing the majority of emissions. Nevertheless most legislation adopted so far relates to stationary sources, with controls over mobile emissions in Europe introduced only in the FRG and Sweden.

Limits on NO_x emissions may be of various types but most countries have chosen to set standards for NO_x emitted in flue gas. The actual levels of emission standards are based on two different principles. One principle is to have a target (mostly high) for the required reduction in total emissions and to set the standards based on that target. Technology must then be found or developed to meet the standards. Examples of this "technology forcing" approach include the Federal Republic of Germany, Austria and Sweden. The other philosophy is to choose a suitable available technology for NO_x reduction and set emission limits according to what can be achieved with that technology. In the UK for instance there is a requirement that the best currently available system of combustion modification suitable for UK boilers and systems should be used, and a design target rather than an emission standard is set.

An alternative to these two major philosophies is to set a target for reduction of the total NO_x emission from a group of sources (eg utilities) and to allow the sources at least in theory to choose where to take action to reach this target. This "bubble" approach has been adopted in Denmark, although constraints on emissions from individual plants may also be applied.

DIFFERENCES IN METHODS OF SETTING STANDARDS

The way in which emission standards for NO_x are set varies in many different ways between the countries. The differences lie mainly in the categories of plants subject to limits, in the units used for emission standards, the time base over which emissions are measured and the levels of the standards.

The categorisation of a plant can be based on:

- unit size
- combustion technology
- total amount of NO_x emissions
- fuel type
- whether it is a new or existing plant.

The most common way of categorising plants is by unit size and fuel type along with whether a plant is new or existing. The Federal Republic of Germany, though, has added to these categories the actual combustion technology. For example, for smaller existing plants there are different emission standards for the same size of plants using the same fuel, depending on whether they use fluidised beds, pulverised firing with dry bottom or with wet bottom. Instead of plant size, Sweden uses the total amount of emitted NO_x as the main category. Plants with larger NO_x emissions are subject to stricter standards than those emitting smaller amounts.

The units used for emission standards also vary between the countries which makes comparison of standards between countries confusing.

The units used are:
- mg/m^3
- g/GJ
- ppm

The most commonly used unit is mg/m^3 at a specified temperature, pressure and oxygen content (generally 0°C, 1.013 bar on dry gas and with O_2 content between 5 and 7%). The Scandinavian countries use g/GJ, where the energy unit stands for the efficient (lower) heat value of the input wet fuel (compared to the American unit lb/MBtu where the heat value is the calorimetric). Levels in ppm are used in the UK.

Standards are also set on different time bases, for example:

- averaged over a month or a year.
- hourly mean values (eg 95% of 48 hour mean values must be within 110% of the standard).

Nine European countries, all in western Europe, now have national limits on NO_x emissions from coal combustion currently in force or agreed for future implementation. The countries are Austria, Belgium, Denmark, Federal Republic of Germany (FRG), Italy, Netherlands, Sweden, Switzerland and the United Kingdom (UK) (see Table 1). Other countries such as Finland, have drafts or proposals for legislation.

EUROPEAN INTERNATIONAL AGREEMENTS AND STANDARDS

THE EC DIRECTIVE

In September 1988 the European Community (EC) formally agreed a directive on "the limitation of emissions of pollutants into the air from large combustion plants". It has taken nearly five years of negotiations to complete.

The directive specifies target reductions in aggregate emissions from existing combustion plants compared with 1980 emission levels. It covers combustion plants having a thermal input of more than 50 MWt, and existing combustion plants are defined as those in place before July 1987.

The reduction targets for existing plants will give a 10% reduction in EC total emissions by 1993 and a 30% reduction by 1998 compared to 1980 baseline figures (see Table 2). Some countries are allowed an increase in emissions such as Greece, Ireland, and Portugal, and the highest reduction targets are set at 40% for Belgium, the FRG, France, Luxembourg and the Netherlands.

The EC Directive also includes emission limits for new plants which must be implemented in each member country by 1990. National authorities may choose whether to treat plants entering service between July 1987 and 1990 as new or existing plants. The limits are 650 mg/m^3 (6% O_2, dry) for plants over 50 MWt or 1300 mg/m^3 for plants firing coal with volatiles over 10%.

UNECE CONVENTION ON LONG-RANGE TRANSBOUNDARY AIR POLLUTION

The United Nations Economic Commission for Europe (UNECE) Convention on Long-Range Transboundary Air Pollution was signed in Geneva in November 1979 by 33 countries.

In November 1988 a legally binding protocol was signed freezing NO_x emissions at 1987 levels (or levels of any earlier year) by 1994. The signatory countries are also required to use the best available technology to control emissions from both stationary and mobile new sources. Twenty five member countries signed the protocol, which must be approved at the annual meeting of the UNECE in June 1989.

NATIONAL EMISSION STANDARDS

The position of NO_x emission standards in Europe is now very dynamic. Further countries are planning to introduce emission standards on NO_x and countries which already have limits are working on extending the groups of plants to which the limits apply or tightening the standards. In addition to the national limits local decisions on special regulations may be applied in many countries. Emission standards are set for different fuels such as coal and other solid fuels, oil, natural gas and municipal waste.

COAL

Table 3 shows the size of plants covered by NO_x emission standards and Table 4 shows the level of standards applied.

Standards for existing coal fired plants have been introduced in the FRG, Italy, the Netherlands and Switzerland and are planned in Sweden and Austria. The FRG, Netherlands, Sweden and Switzerland have set standards for plants of sizes below 50 MWt; Austria has legislation for plants over 50 MWt.

The most stringent standards for existing plants currently in force are in the FRG, where they vary between 200-1300 mg/m^3. However from 1995 Swedish plants will have to comply with even tighter standards at 50-200 mg/MJ (equivalent to around 140-560 mg/m^3 at 6% O_2 dry). Standards in Switzerland and planned for Austria are similar to the FRG levels, whilst those in Italy and the Netherlands are less stringent.

NO_x emission standards for new plants are applied to small boilers (5-10 MWt) in the FRG, Italy, the Netherlands and Sweden. In most other countries the size limit for new boiler emission standards is 50 MWt but in the UK limits have so far only been set for plants over 700 MWt. Legislation covering smaller new boilers is being drafted. As with existing plants, Sweden now has the tightest NO_x emission standards for new coal fired plants at 50 mg/MJ (around 140 mg/m^3). A limit of 200 mg/m^3 applies to boilers over 300 MWt in the FRG and Switzerland. Other countries with legislation on NO_x emissions from new plants have limits ranging from 400-800 mg/m^3.

OIL AND NATURAL GAS

Almost all countries with national NO_x emission standards for coal combustion also have standards for oil and natural gas fired plants (see Table 5). The emission levels for oil and natural gas fired plants are shown in Table 6. In most cases the limits for oil and natural gas are set lower than or equal to those for coal. However in the UK limits for coal are lower than limits for oil firing, and in Sweden the standards for coal are tighter than those for either oil or gas.

The lowest emission levels for new oil-fired plants are in Sweden (~140-560 mg/m^3) and in the FRG (200-450 mg/m^3). On existing plants the lowest levels will be in Austria (150-450 mg/m^3) and in Sweden (~140-560 mg/m^3) starting from the mid 1990s. Only the FRG and Italy (1200 mg/m^3) and the Netherlands (700 mg/$m^3$3) have currently applicable limits on existing oil-fired boilers.

Fewer countries have limits on natural gas burning and the levels for gas are lower compared with those set for oil. The countries with NO_x emission standards for gas firing are Austria, Belgium, the FRG, the Netherlands, Sweden and Switzerland. For new plants the limits are set between 100-560 mg/m^3 and for existing plants between 140-560 mg/m^3.

WASTE INCINERATORS

The only countries with national NO_x emission limits for waste incinerators are the FRG and Austria. The limit in the FRG is 500 mg/m^3 for all plants (at 11% O_2 for feed rates >750 kg waste/h, 17% O_2 for feed rates <750 kg/waste/h) and in Austria 100 mg/m^3 for plants larger than 750 kg waste/h.

IMPLEMENTATION OF NO_x CONTROL LEGISLATION

FLUE GAS TREATMENT

In the FRG stringent NO_x emission standards were set in 1983 and had to be implemented on many plants by the end of 1989. The standards were set independently of the status of NO_x reduction technology and to meet them flue gas treatment had to be used. A large amount of treatment plant has been installed simultaneously (3). The standards for new boilers had to be implemented very quickly, which meant that for some plants almost at construction phase the design had to be changed and a deNO_x plant added at the last minute. The first deNO_x system began operation in the end of 1985. By 1990 plants with a total capacity of 32,000 MWe will be equipped with flue gas treatment for NO_x reduction in the FRG. The capacity will be divided between different fuels as follows:

coal fired, dry bottom	51%
coal fired, wet bottom	39%
lignite, oil and gas fired	10%

70% of the total coal-fired boiler capacity will then be equipped with flue gas treatment, dominated by hard coal fired plants.

In Austria, almost all hard coal-fired utility plants are equipped with flue gas treatment, giving a total capacity of 1400 MWe. Gas and oil fired plants with a capacity of 800 MWe are also equipped with $deNO_x$ (4).

Two municipal waste incinerator plants are expected to be operating with $deNO_x$ this year, one in the FRG and the other in Austria. Other countries with commercial applications of flue gas treatment are Denmark and the Netherlands.

The distribution of systems for $deNO_x$ flue gas treatment anticipated to be in commercial operation in Europe in 1990 can be seen in Table 7 and Figure 1. Most of the total capacity of 35,000 MWe equipped with flue gas $deNO_x$ is situated in the FRG. Over 90% of coal fired plants with $deNO_x$ in the FRG are equipped with SCR. In Europe, the most common location of the catalyst is before the air preheater and electrostatic precipitator, (high dust) comprising 62% of the capacity. A further 36% has the catalyst situated after the flue gas desulphurisation unit (tail end) and in 2% the catalyst is situated between the electrostatic precipitator and the air preheater (low dust). The high dust location dominated the earliest plants but the tail end location has become more popular recently for various reasons.

Work on SCR and SNCR techniques has been proceeding in other countries. Pilot plants and tests have been completed and are ongoing on SCR and SNCR in countries like Denmark, the Netherlands, Italy and Sweden. Techniques are also being developed for simultaneous SO_x and NO_x abatement in Denmark and the FRG.

In Denmark, Finland, the Netherlands and Sweden flue gas cleaning in combination with advanced combustion control will be necessary to meet the planned and proposed emission standards.

COMBUSTION CONTROL

Most other countries have so far been working mainly with combustion control techniques. In the UK the main utility is assessing different techniques that are suitable for different boiler configurations as part of a programme to retrofit all existing major coal fired power stations with low NO_x burners over a period of 10 years. The programme will involve all generating units with a capacity of 500 MWe or over and would affect about 25,000 MWe.

Work has also been undertaken in the FRG on combustion control technologies. For most of the lignite fired boilers this is expected to be sufficient to meet the emission standards. Techniques used for combustion control include staged combustion, over fire air, and low NO_x burners among others. In Austria, lignite fired plants will have combustion modification. Combustion control is also the main measure for gas and oil fired plants.

Other ways to reduce the emissions from stationary sources that may also be used in the future could be to increase the total efficiency of the plant and thus reduce emissions per unit of useful energy. As different combustion technologies emit different amounts of NO_x, it will become more important to have emission levels as one criterion when choosing a combustion technology.

That will favour technologies such as fluidised bed combustors and gasification which are reported to produce low NO_x emissions.

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Figure 1 Estimated market share of deNO_x systems on coal-fired plants in Europe in 1990

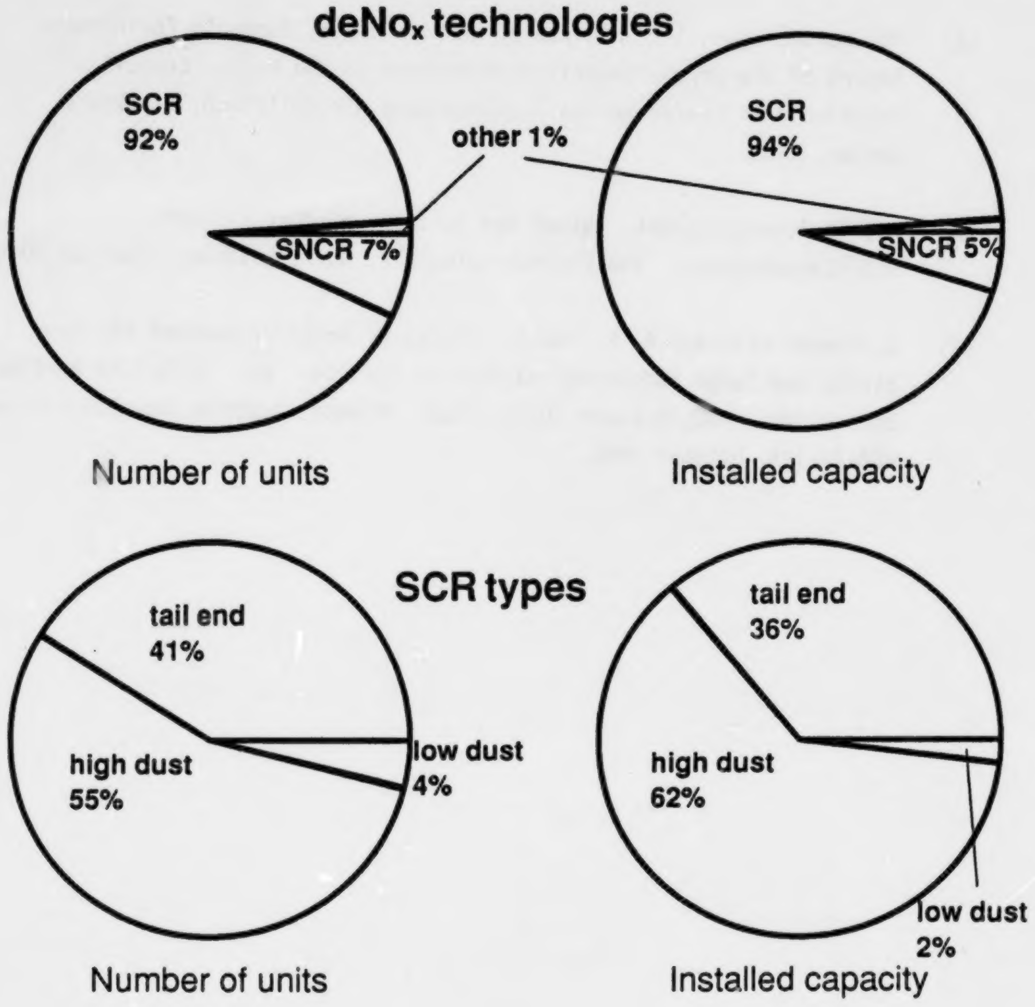

Table 1 European countries with controls over NO_x emissions from coal combustion (1)

	New plants		Existing plants	
	current	planned	current	planned
Austria	+			+ *
Belgium	+			
Denmark	+			
FRG	+		+	
Italy	+		+	
Netherlands	+		+	
Sweden	+			+ **
Switzerland	+		+	
UK	+			
EC	+			

* from 1994
** from 1995

Table 2 NO_x emissions reduction targets for existing plants over 50 MWt in the EC (1)

Country	1980 baseline (10^3 t NO_x)	1993 target % reduction	1998 target % reduction
Belgium	110	-20	-40
Denmark	124	-3	-35
FRG	870	-20	-40
Greece	36	+94	+94
Spain	366	+1	-24
France	400	-20	-40
Ireland	28	+79	+79
Italy	580	-2	-26
Luxembourg	3	-20	-40
Netherlands	122	-20	-40
Portugal	23	+157	+178
UK	1016	-15	-30
Total	**3678**	-10	-30

Table 3 Sizes of plants covered by NO_x control regulations (1)

	New plants current	Existing plants current	 planned
Austria	>50 MWt	-	>50 MWt
Belgium	>50 MWt	-	-
Denmark	>50 MWt	-	-
FRG	>1 MWt	>50 MWt >1 MWt**	- -
Italy	>100 MWt	>400 MWt	-
Netherlands	*	*	-
Sweden	*	-	*
Switzerland	>1 MWt	>1 MWt	-
UK	>700 MWt	-	-
EC	>50 MWt	-	-

* no minimum plant size stated in regulations
** CFB

Table 4 Range of NO_x emission standards for coal combustion plants in European countries (1)

	New plants current (mg/m^3)	planned (mg/m^3)	Existing plants current (mg/m^3)	planned (mg/m^3)
Austria	800			200-600*
Belgium	650-800	200-400**		
Denmark	1150 (1)			
FRG	200-500		200-1300	
Italy	650		1200	
Netherlands	400-800		1100	
Sweden	140 (2)			140-280 (3)***
Switzerland	200-300		200-500	
UK	670 (4)			
EC	650-1300			

(1) 400 mg/MJ
(2) 50 mg/MJ
(3) 50-200 mg/MJ
(4) 330 ppm
* from 1994
** from 1996
*** from 1995

Note: The standards in mg/m^3 are based on standard temperature and pressure at 6% O_2 on dry flue gas, except for some types of combustion technology in the FRG where the O_2 level is between 5 and 7%.

Table 5 European countries with NO_x regulations on oil and natural gas combustion plants

	Oil fired plants		Natural gas fired plants	
	new	existing	new	existing
Austria	+	+ *	+	+ *
Belgium	+		+	
FRG	+	+	+	+
Italy	+	+		
Netherlands	+	+	+	+
Sweden	+	+ **	+	+ **
UK	+			
EC	+		+	

* from 1994
** from 1995

Table 6 Range of NO_x emission standards for oil and natural gas combustion plants in European countries

	Oil fired plants		Natural gas fired plants	
	new (mg/m^3)	existing (mg/m^3)	new (mg/m^3)	existing (mg/m^3)
Austria	450	150-450 *	350	150-300 *
Belgium	450 (150 **)		350 (100 **)	
FRG	250-450	250-700	200-350	200-500
Italy	650	1200		
Netherlands	300	700	200	500
Sweden	140-560 (1)	140-560 **(1)	140-560 (1)	140-560 **(1)
Switzerland	150-450		100-200	
UK	564			
EC	450		350	

* from 1994
from 1995
(1) 50-200 mg/MJ

Note: The standards in mg/m^3 are based on standard temperature and pressure at 3% O_2.

Table 7 Estimated number and capacity $DeNO_x$ plants in Europe in 1990

	FRG		Austria		Rest of Europe		Total	
	number	capacity (MWe)	number	capacity (MWe)	number	capacity (MWe)	number	capacity (MWe)
Coal								
SCR	105	29 000	4	1 340	1	130 (1)	110	30 470
SNCR	5	1 000	2	440	1	130 (2)	8	1 570
Activated carbon	1	200					1	200
Oil and gas								
SCR	10	1 700	3	800			13	2 500
Waste								
SCR	1		1				2	
Total	**122**	**31 900**	**10**	**2 580**	**2**	**260**	**134**	**34 740**

(1) The Netherlands
(2) Denmark

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ENVIRONMENTAL EFFECTS OF NITROGEN OXIDES

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Over the past few years, the utility industry's main concern over air quality and the environment has been with sulfur dioxide emissions. The importance of nitrogen oxides, however, should not be overlooked because they can bear on such environmental concerns as damage to ecosystems through acid rain, human health, and visibility degradation. But present utility concerns over NO_x focus primarily on its role in ozone formation. The fact that dozens of metropolitan areas are in a state of nonattainment is a major concern to the utility industry. As recently as 1987, EPA designated 65 urban areas as nonattainment for ozone, and those 65 areas have an estimated population of nearly 130 million people.

Ozone is a health concern, and humans appear to be particularly sensitive to ozone exposure during exercise. The U.S. Office of Technology Assessment estimates that about 80,000 people are exposed to levels of ozone exceeding 9.12 ppm (the U.S. ambient standard) while doing heavy exercise, for an average of about 4 hours per person per year. The population exposed to concentrations exceeding the standard increases to 13 million when performing moderate exercise, for an average of about 6 hours per person per year, and 21 million are estimated to be exposed to levels exceeding the standard while performing low exercise, for an average of 8 hours per person per year. Ozone reduction in nonattainment areas is a matter of high concern.

The utility is concerned over health consequences. But is is also concerned over proposals for more stringent NO_2 legislation which would be costly to the industry and to consumers but which might do little to alleviate the NO_x/ozone issue and, in fact, might exacerbate it. The chemistry of ozone formation is such that a simple reduction of the NO_x precursor does not necessarily insure a reduction in atmospheric ozone.

Figure 1 is an overly simplified picture of the atmospheric chemistry of ozone formation. Despite the simplification, it does point out the importance of volatile organic compounds (VOC) in allowing accumulation of ozone. Without VOC, a steady NO_2-NO-O_3 state is reached, depending on sunlight intensity. Obviously, the ratio of VOC to NO is critical in defining the ultimate atmospheric concentration of ozone. High VOC:NO ratios will favor ozone formation. Conversely, high NO:VOC ratios favor attainment of steady state. But in the steady state situation, reduction of NO_x emissions could increase the role of whatever VOC is present thereby actually leading to an increase in ozone. The situation is not simple. Reduction is VOC will almost certainly result in ozone reduction; reduction in NO_x may or may not (Fig. 2).

Recently, EPRI decided to evaluate the efficiency of NO_x control in reducing ozone in an urban area. To do so, it applied the EPA Urban Airshed 4 model to Philadelphia, Pennsylvania, a nonattainment urban area. Data on air quality and meteorology came from a July 1979 study conducted by EPA. Detailed emission inventories for hydrocarbons and NO_x were included in the exercise. The model was run against observed (1-hour average) ozone concentrations at ground level for a test-case day (July 19, 1979) - the base case. The model was run for four emission reduction "scenarios" with results being compared to the base case. The four "scenarios" were:

- S1 25% reduction of only VOC emissions
- S2 25% reduction of VOC plus 25% reduction of power plant NO_x
- S3 25% reduction of VOC plus 25% reduction of all NO_x (mobile and stationary sources)
- S4 25% reduction of only power plant NO_x emissions

The modeling results (in summary) are as follows:

- S1 ozone decreased by 0.01 - 0.02 ppm
- S2 ozone increased by 0.01 - 0,02 ppm
- S3 ozone increased in Some areas, decreased in others
- S4 ozone increased by 0.01 - 0.03 ppm

Obviously reduction in NO_x yields uncertain improvement in ambient ozone concentrations. VOC reduction alone leads to decreased ozone. NO_x reduction alone leads to increased ozone. Reducing both NO_x and VOC leads to more complicated results.

The above-cited example of a model exercise is not cited as a reason for avoiding NO_x control. It is given only to caution that any NO_x control should consider the complexities of atmospheric chemistry as an important part in judging what results will be achieved.

Concern over ozone is not the only reason for the utility interest in NO_x. Nitrogen oxides play a role in acid rain. Acid rain is essentially a dilute solution of sulfuric and nitric acids plus minor contributions form carbonic and organic acids, the two strong acids commonly accounting for over 90 percent of the acidity. In the eastern U.S. and western Europe, the sulfuric/nitric ratio, in terms of acidity contribution is typically about 2.1. Sulfuric acid contributions tend to be higher in eastern Europe and in Some metropolitan areas where vehicular NO_x emission are high (e.g., in Los Angeles), the nitric acid component may exceed that of sulfuric acid.

Nitric acid is obviously an important component of acid rain. It is derived, essentially, by gas phase oxidation of NO_2 according to the reaction:

$$NO_2 + OH + m = HNO_3$$

where m is any third body which absorbs energy, viz., N_2 or 0_2. At night, NO_2 would be oxidized by any ozone present to nitrate radical which, in reacting with N_2 would yield N_2O_5 and ultimately nitric acid. This reaction points out that NO_x control does, indeed, bear on the acidity of precipitation. Most U.S. attention to acid rain, however, has focused on SO_2 rather than on NO_x control for two reasons: (1) the technical aspect of SO_2 control is less demanding that for NO_x, and (2) sulfuric acid accounts for nearly 2/3 of the precipitation acidity, hence attention to control the major component of acid rain was considered warranted.

Will a reduction in NO_x emissions play a significant role in alleviating any damage that might be attributed to acid rain. We now have extensive data showing that rain acidity, at ambient concentration, has little harmful effect on crops in terms of growth or yield. In fact, the overall net impact of the nitrogen component of the rain has a positive fertilizing effect. An NO_x reduction, therefore, would be of little value in protecting crops because they don't need protection.

The forest situation is still not entirely clear, but at least in America, acid rain may not be a major contributor to observed forest decline. The nitrogen component of acid rain has been cited as a cause of forest decline as a result of excess nitrogen fertilization. That concept, however, has not be substantiated.

Perhaps the major acid rain concern in the U.S. has been that over aquatic systems, particularly concern over lakes which are not acid but which are considered "sensitive" - the concern being that such "low sensitivity" lakes will soon go acid under present ambient acid rain conditions. We have applied an EPRI-developed model (ILWAS) to many such lakes to assess the effect, not just of continued deposition of rain at current acid levels, but of deposition of increased acidity as a result of increased sulfuric acid loading. We find that many lakes classed as "sensitive" have considerable neutralizing reserve to counter even increased sulfuric acid input. Because of its lesser contribution to precipitation acidity, nitric acid is less of a concern than sulfuric acid. We find that lakes do, in fact, show less response to nitric than to sulfuric acid, not only because of the lower amounts of nitric acid in acid rain, but because watersheds have natural sinks for nitrogen thereby limiting the amount of nitric acid which actually enters the lakes.

A third environmental concern over NLO_x emission is that related to the global climate/greenhouse gas issue. Nitrous oxide (N_2O) is an infrared absorbing gas and can play a role in any future climate problems we may face. Recent studies suggest that utility emissions of N_2 are not nearly as large as previously suspected. The subject, as well as that dealing with global emissions inventories of N_2O, is currently under study by EPRI.

Another environmental effect warranting serious concern is that dealing with human health, specifically with pulmonary function, and NO_2 inhalation. As a result of human clinical studies, we know that NO_2 produces a decrement in pulmonary function less than that from exposure to ozone but more than that for SO_2. Admittedly, the NO_2 exposure levels used (a few tenths of a part/million) far exceed typical ambient levels but studies, so far, have focused on acute effects. The question of effects from chronic exposure to lower levels of N_2 is unanswered. Likewise the exacerbating role of particulate matter in conjunction with N_2 is uncertain. We have Some evidence from animal toxicology studies that NO_2 in combination with particles may result in synergism. Again, this issue is being investigated by EPRI.

The chemistry associated with nitrogen oxides in the atmosphere is not simple and is perhaps even less understood than that of sulfur dioxide which has received much attention over the past decade. Some oxidation reactions are not linear, hence predicting the results of precursor reduction on concentrations of reactants is uncertain in many instances. Furthermore, alleviating one environmental concern may well exacerate another. Any consideration of NO_x control, therefore, might best be approached in a holistic manner simply because atmospheric constitutents are not isolated from each other and changes in one can affects many reactions - even those involving other pollutants.

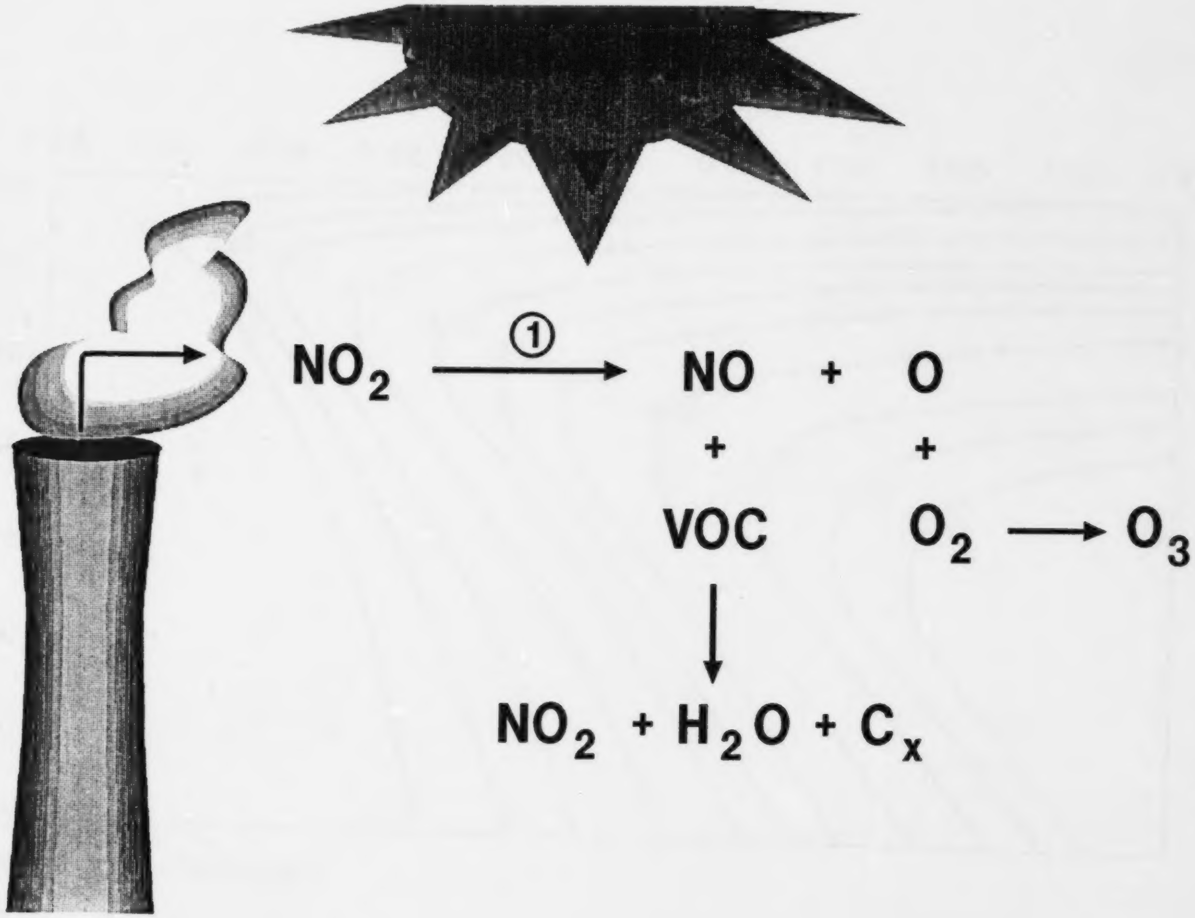
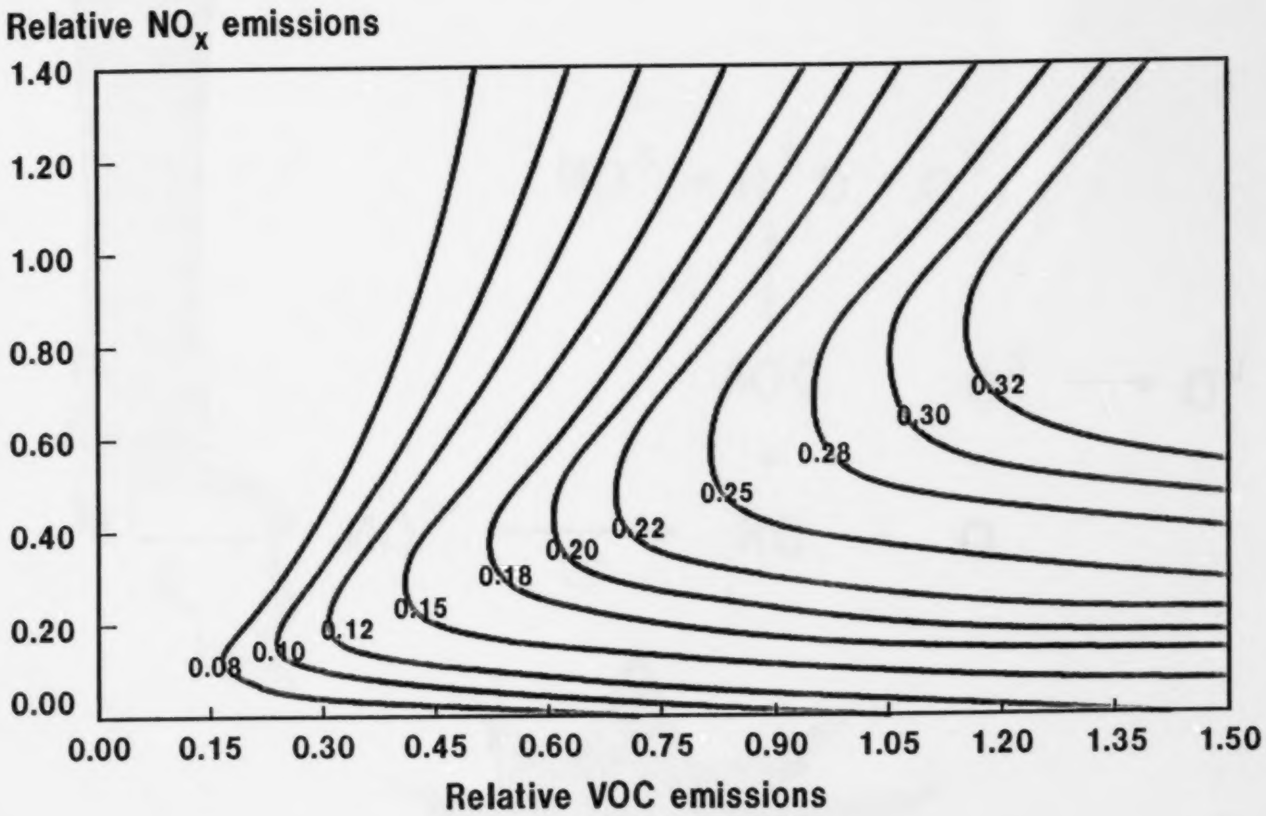

NO_2
①
NO + O
+ +
VOC O_2 → O_3
NO_2 + H_2O + C_x

FIGURE 1

8580.04 A



8580.07 B

FIGURE 2

N_2O EMISSIONS FROM FOSSIL FUEL COMBUSTION

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ABSTRACT

On-line nitrous oxide (N_2O) measurements from six full-scale, coal-fired utility boilers indicate direct N_2O emissions of less than 5 ppm. Laboratory and pilot-scale experiments conducted to further characterize direct N_2O emissions are consistent with the field data indicating on-line N_2O concentrations below 5 ppm. Further sub-scale coal experiments using air staging and natural gas reburning for NO_x control show only slight increases in N_2O emissions. These results question the reliability of the existing N_2O data base, much of which is likely affected by a sampling artifact by which N_2O can be produced in sample containers, awaiting analysis, through an as-yet-unknown mechanism possibly involving NO, SO_2, and water. Time resolved measurements of N_2O, NO, and SO_2 from combustion emissions, collected in stainless steel sample containers, show that N_2O concentrations in wet samples can increase to levels greater than 100 ppm in less than 24 hours. These increases are reduced (but not eliminated) in dried samples. All samples show that NO reacts (possibly forming NO_2) within 4 hours. SO_2 concentrations decrease with time at rates related to the sample dryness. These results suggest the need for further research to identify other direct and indirect sources of N_2O.

INTRODUCTION

The atmospheric concentration of nitrous oxide (N_2O) is reported to be increasing at a rate of between 0.18 and 0.26 percent per year(1,2) from its present level of 303 ppb.(3) This is a matter of concern because N_2O has been implicated as both a "greenhouse" gas and a participant in stratospheric ozone depletion mechanisms. Fossil fuel combustion has been proposed as a possible major contributor to the measured increases in ambient N_2O concentrations, as these increases seem to track measured increases in ambient CO_2 concentrations. Additionally, limited data of direct N_2O emissions from fossil fuel combustion had indicated stack emissions exceeding 100 ppm, and an approximate average N_2O-N:NO_x molar ratio of 0.58:1.(3) These concerns, implications, and the limited data available prompted the U.S. Environmental Protection Agency (EPA) to stimulate collaborative national and international research programs with industry, academia, and other government agencies to better characterize the anthropogenic sources of N_2O. While partial summaries of these programs are presented elsewhere in the form of workshop proceedings(4,5), the purpose of this paper is to present the results of research and testing designed to characterize the direct N_2O emissions from stationary fossil fuel combustion. This research and testing was sponsored by the U.S. EPA through its Office of Policy, Planning, and Evaluation (OPPE) and Office of Air and Radiation (OAR), and was performed by EPA's Air and Energy Engineering Research Laboratory (AEERL). A portion of this work was sponsored by the U.S. Department of Energy (DOE).

Historical Data Base

A summary of the N_2O data base from stationary fossil fuel combustion as it existed following the second N_2O workshop, which was held in September 1987, is presented in Figure 1.(5) The open and half-filled symbols represent data from laboratory, pilot, and full-scale combustion systems taken by several research groups who first attempted N_2O measurement. Also included in Figure 1 is a line representing a proposed N_2O-N:NO_x molar ratio of 0.58:1.(3) The fully filled symbols represent data taken by our group using a laboratory-scale downfired coal combustor (2.3 kg/hr, 5 lb/hr) burning two western coals. These data (fully filled symbols), indicating direct N_2O emissions typically less tham 10 ppm, were presented but were not included in the workshop proceedings. At the time, these on-line gas chromatograph/electron capture detector (GC/ECD) data were considered suspect due to the limited number of data points, the untested sampling procedure, the poor condition of the analytical system, and the large discrepancies compared to the existing data base.

In an effort to improve the data quality, AEERL aquired a new dedicated GC/ECD system, set it up in a laboratory, and changed the sampling procedure to that used by several other research groups. This sampling procedure involved using stainless steel sampling containers and then scheduling the N_2O analyses. The results of these changes are presented in Figure 2. Again, fully filled symbols represent the data taken by this group burning the same two western coals, and are compared to the existing historical data (open and half-filled symbols). Variations in stoichiometry and burner swirl were used to affect NO_x (and possibly N_2O) concentrations. The new data were highly scattered, but agreed better with the existing data. These data were presented at the third N_2O workshop that was held in June 1988. At that meeting Muzio et al., conducting EPRI/EPA sponsored research, presented data suggesting the presence of an N_2O sampling artifact.(6) They presented evidence that indicated that N_2O might be produced in sampling containers awaiting analysis. They further hypothesized a mechanism of this formation involving NO, SO_2, and water. This evidence questioned the validity of all existing data which involved container sampling.

Based on this evidence, AEERL renewed efforts to characterize, by on-line means, the direct N_2O emissions from several laboratory and pilot-scale combustion systems burning a variety of coals, fuel oils, and natural gas. Additionally, we sought to compare the results from these sub-scale systems to direct N_2O measurements (by on-line techniques) from full-scale pulverized-coal-fired utility boilers. Concurrent with all on-line analyses, we sought to characterize the time dependent evolution of N_2O, NO, and SO_2 in container samples.

ON-LINE MEASUREMENTS

Laboratory and Pilot-Scale Experiments

Three AEERL combustion systems that were used for the sub-scale experiments included a 29 kW (100,000 Btu/hr) refractory-lined, downfired, coal-fired tunnel combustor (Downfired Tunnel Furnace), a 733 kW (2,500,000 Btu/hr) gas/oil-fired, fire-tube package boiler (North American Boiler), and an 879 kW (3,000,000 Btu/hr) gas/oil-fired, water-tube package boiler simulator equipped with a low NO_x burner/precombustor (Low NO_x Burner/Package Boiler Simulator). Details regarding the specific designs of these systems have been presented elsewhere(7,8,9) and will not be reiterated here.

Although several analytical techniques in addition to GC/ECD are applicable to on-line N_2O analysis from combustion sources(4,6,10), most involve extractive sampling. The sampling system used at AEERL included extractive sampling through a stainless steel sampling probe, heated, 0.64 cm (0.25 in.) outside diameter (O.D.) Teflon tubing and particulate filter, water removal by use of a refrigeration drying system, and then pumping by means of a Teflon diaphragm sample pump through silica gel dessicant to continuous emission monitors (CEMs). CEMs included measurement of O_2, CO, CO_2, and NO. Immediately after the sample pump, a portion of the sample was directed to a 1 ml/six port GC sampling valve for on-line N_2O analysis by GC/ECD (Shimadzu Model GC-9A). SO_2 was measured from a heated sample taken downstream of the filter and upstream of the refrigeration dryer. The GC used to quantify N_2O utilized 5 percent methane in argon carrier gas at 20 cm^3/min., a 3.8 cm (1.5 in.) long by 0.64 cm (0.25 in.) O.D. P_2O_5 precolumn, a 3.66 m (12 ft) long by 0.32 cm (0.125 in.) O.D. stainless steel Poropak Super Q column at 35 °C, and a Ni^{63} ECD maintained at 330 °C.

Table 1 presents the combustion conditions and average on-line N_2O and CEM data for 10 AEERL tests involving the three combustion units and seven fuels including four types of coal. Evident from Table 1 is that the direct N_2O emissions from all tests never exceeded 5 ppm. In fact several natural gas and No. 2 fuel oil data indicate N_2O concentrations less than the instrument detection limit of 0.24 ppm. The coal tests showed the highest levels (2 to 4 ppm), and little difference could be discerned between the two fuel oil and natural gas tests. Data from the low NO_x burner/package boiler simulator, with and without air staging strategies for NO_x control, showed that, while significant NO reduction was seen with air staging, no measureable effect was detected in corresponding N_2O concentrations. These data, however, are too close to the instrument detection limit for accurate analysis. The other CEM measurements are comparable to those typical of full-scale units.

Experimental work on N_2O emissions from laboratory-scale coal combustors has also been completed at the University of Arizona (UA), under the sponsorship of the U.S. DOE. The downfired laboratory combustor used in that work was very similar in size and design to that described above for the AEERL tests, except that the pulverized coal flame was "premixed," and the overall configuration resembled a plug flow reactor. The flue gas sample to be analyzed was withdrawn through a water cooled, water quenched probe. The water was removed in a refrigerated knockout pot, and the sample was passed through a 1 ml gas sampling valve into a Shimadzu Model GC-8A GC equipped with a 3.66 m (12 ft) long, 0.32 cm (0.125 in.) O.D. stainless steel column packed with Porapak Q, conditioned at 220 °C. An ECD, operating at 250 °C, required the use of argon with 5.22 percent methane as the carrier gas. Complete details of the sampling and analysis procedure can be found elsewhere.(11) Table 1 also presents four data sets from the University of Arizona work, representing exhaust conditions under baseline, air staging, and natural gas reburning conditions for a Utah bituminous coal. These data are consistent with the on-line AEERL data.

Figure 3 shows values of exhaust NO and N_2O emissions as a function of stoichiometric ratio for a Utah bituminous coal. N_2O levels vary from 0.5 to 1.5 ppm. Time resolved profiles during air staging are shown on Figures 3b (primary SR=0.86) and 3c (primary SR=0.65), and demonstrate the interesting fact that staging causes an increase in N_2O near the staging point. However, N_2O levels are still exceedingly low and so the effect is not of practical significance. Figure 3d shows time resolved NO and N_2O profiles along the combustor axis during employment of reburning as a NO_x control technique. We observed an increase of N_2O at the point of air injection, similar to what was observed under air staged conditions. For all configurations, however, these on-line measurements of N_2O yielded extremely low values, and indicated that direct N_2O emissions did not appear large from pulverized coal combustion, either with or without combustion modifications for NO_x control.

Field Tests

Following the laboratory and pilot-scale experiments, AEERL sponsored a field study to characterize the direct emissions of N_2O from full-scale, coal-fired utility boilers. These measurements were conducted by Acurex Corporation at six boilers ranging in size from 165 to 700 MW, including Circular, Triple Cell, and Tangential designs manufactured by Babcock & Wilcox, Riley Stoker, and Combustion Engineering. These units burned primarily a medium sulfur Alabama bituminous coal. The sulfur content of this coal is reported to be in the range of 1.5 to 2.0 percent. The sampling and analytical methods used were similar to those described above for the AEERL sub-scale experiments. Table 2 presents the average on-line N_2O and CEM data for each of the six utility units. All on-line N_2O measurements were below 5 ppm. In fact, almost all of the on-line N_2O measurements were below the detection limits of the two GC/ECD systems used (1.2 and 3.6 ppm). These samples were taken at existing sampling locations, downstream of all economizer and particulate removal equipment, either before or after the systems' induced draft fan. All six units were operated at or near full load during the tests. Limited SO_2 data were collected due to problems with the SO_2 analyzer.

A summary of the on-line data from both the sub-scale and full-scale studies is presented in Figure 4. Again, these data (indicated by the fully filled symbols) are compared to the previous data base (open and half-filled symbols). These results suggest that the direct emission of N_2O from coal-fired utility boilers is likely low (less than 5 ppm), that the existing data are suspect due to an as-yet-undefined sampling artifact, and that no simple N_2O/NO_x correlation exists. The data do not indicate, however, that other types of combustion sources are not major N_2O emitters, or that indirect mechanisms of atmospheric N_2O formation from combustion emissions do not exist.

TIME RESOLVED MEASUREMENTS FROM SAMPLE CONTAINERS

Concurrent with all on-line activities, extracted samples were collected in stainless steel sampling containers for time dependent analyses of N_2O by GC/ECD, NO by GC/thermal conductivity detector (TCD), and SO_2 by GC/flame photometric detector (FPD) techniques. These samples were collected at three degrees of dryness including wet samples (before refrigeration dryer), partially dried samples (immediately after refrigeration system), and dessicated samples (after additional drying by use of a P_2O_5 filled canister). Samples from the sub-scale experiments were analyzed at 1, 4, 24, 48, 168, and 336 hours. Samples from the full-scale tests were analyzed at 1, 4, 48, 168, and 336 hours. Time-resolved NO measurements were not taken for the full-scale tests due to limited availability of field equipment. Additionally, limited time resolved SO_2 data were produced from the full-scale tests due to instrument problems in the field.

Samples for time resolved analyses were collected in 0.5 L stainless steel containers. These containers were fitted with septums for sample extraction by gas syringe. A number of samples were collected in glass containers of similar size for comparison. While the available data for this comparison are very limited, they indicate similar sample evolution trends in each type of container. However, the rate of N_2O increase may be somewhat lower in glass containers. Combustion gas and N_2O calibration gas (10 ppm) samples of varying moisture content were passed through beds of different desiccants and analyzed to determine any effect of selective water removal on N_2O. Three desiccants were tested including phosphorus pentoxide (P_2O_5), magnesium perchlorate [$Mg(ClO_4)_2$], and silica gel (SiO_2). None of these desiccants was seen to affect the N_2O concentration. P_2O_5 was chosen as the desiccant of choice for these tests due to its almost quantitative ability to remove water. Tests were also conducted to identify sorbents for the selective removal of SO_2 from the extracted gas samples. Sodium hydroxide (NaOH) and calcium hydroxide (CaOH) have been examined as possible candidates. The data presented here, however, do not include any sample processing for SO_2 removal.

Figures 5 through 8 present the results of these time resolved analyses. In an effort to conserve space, only selected data (indicative of general trends) will be presented. Figures 5a and 5b present the evolution of N_2O and SO_2 from samples taken during the Utah bituminous laboratory-scale coal experiments. Figure 5c presents similar N_2O evolution data for the full-scale coal-fired utility boiler tests from unit D. It is interesting to note that both the sub-scale and full-scale N_2O data from wet or partially dry samples show rapid increases in the first minutes and hours after sampling. Smaller (but non-negligible) increases are seen in the dry samples. Maximum N_2O values from wet samples are seen after 24 hours. These values (200 and 75 ppm) are comparable to those presented by the historical data and the proposed N_2O-N:NO_x correlation (Figure 1). The maximum N_2O concentration is likely related to the initial NO and SO_2 concentrations. This speculation is supported by comparing the N_2O and initial NO data from these two tests. Figure 5 shows the N_2O concentrations in the wet and partially dry samples to slowly decrease after 24 to 48 hours. This reduction, however, may be due to slight air leaks into the sample containers due to numerous septum punctures and the volume of sample removed. Steps were taken in later data collection activities to limit the number of samples taken from each container and increase the number of containers used. Figure 5b shows that the evolution of SO_2 seems to be very much dependent on the sample dryness. These data are presented out to 168 hours to increase the resolution at the lower times. NO data (not presented) all show rapid removal/reaction (possibly forming NO_2) within 1 to 4 hours regardless of the moisture content of the samples.

Figures 6 and 7 present similar data for No. 5 and No. 2 fuel oils, respectively, from the two smaller-scale combustion systems. Similar behavior, as compared with the coal data, is evident with respect to both N_2O and SO_2. Again, NO was removed/reacted to below detectable levels within 1 to 4 hours. It is interesting to note that, while the trends are similar to those seen for coal, the magnitude of the artifact is much less for the two fuel oils. The data presented are also consistent with the supposition that the resulting N_2O formation is dependent on the initial NO and SO_2 levels (in addition to the moisture). Note that N_2O increases seen in the Package Boiler Simulator samples (where NO_x control was used) are significantly smaller than those seen in the North American Boiler samples (without NO_x control) burning the same fuels.

The evolution of N_2O from samples from these same two units burning natural gas is presented in Figure 8. SO_2 emissions were for the most part below detectable levels. And again, NO was removed from all samples within 1 hour. The N_2O data are inconclusive. Some of the data suggest that the artifact still exists at minimal SO_2 levels, while other data show this effect to be negligible. Further samples from natural gas flames are planned to investigate this further.

CONCLUSIONS

Results from on-line (GC/ECD) N_2O measurements from six full-scale utility boilers burning a medium sulfur Alabama bituminous coal indicate direct N_2O emissions of less than 5 ppm. Additional results from laboratory and pilot-scale combustion experiments using similar procedures and burning a variety of coals, fuel oils, and natural gas are consistent with these full-scale N_2O data. Further experiments using a laboratory-scale coal combustor indicate that combustion modifications used for NO_x control may cause slight increases in N_2O emissions. These increases, however, are minor, causing overall increases of less than 5 ppm. These results question the reliability of the existing historical data base, much of which is likely affected by a sampling artifact. These historical data had indicated direct N_2O emissions exceeding 100 ppm. Additionally, these past data had suggested a linear N_2O-N:NO_x molar ratio of approximately 0.58:1.

Time resolved analyses of samples collected in stainless steel containers suggest that N_2O can be produced in the sample awaiting analysis within minutes. While the mechanism of this formation is unknown, it seems directly dependent on the initial concentrations of water, SO_2, and NO in the sample. This artifact can be reduced (but not eliminated) by removing the moisture present in the sample by desiccation. Characterization of full-scale combustion emissions in the field by container sampling is much more cost effective compared to on-line analyses. Hence, efforts are continuing to examine techniques for the selective removal of SO_2 in order to minimize the effects of the artifact in container samples.

The data indicate that the direct emission of N_2O from pulverized-coal-fired utility boilers is likely to be low (< 5 ppm). The data, however, do not support the conclusion that other types of combustion sources are not major N_2O emitters, nor do the data indicate that indirect mechanisms of atmospheric N_2O formation involving the constituents of combustion emissions do not exist. Identification of the mechanisms involved with the sampling artifact may shed some light as to whether similar mechanisms could exist in the atmosphere.

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DISCLAIMER

The research described in this article has been reviewed by the Air and Energy Engineering Research Laboratory, U.S. Environmental Protection Agency, and approved for publication. The contents of this article should not be construed to represent Agency policy nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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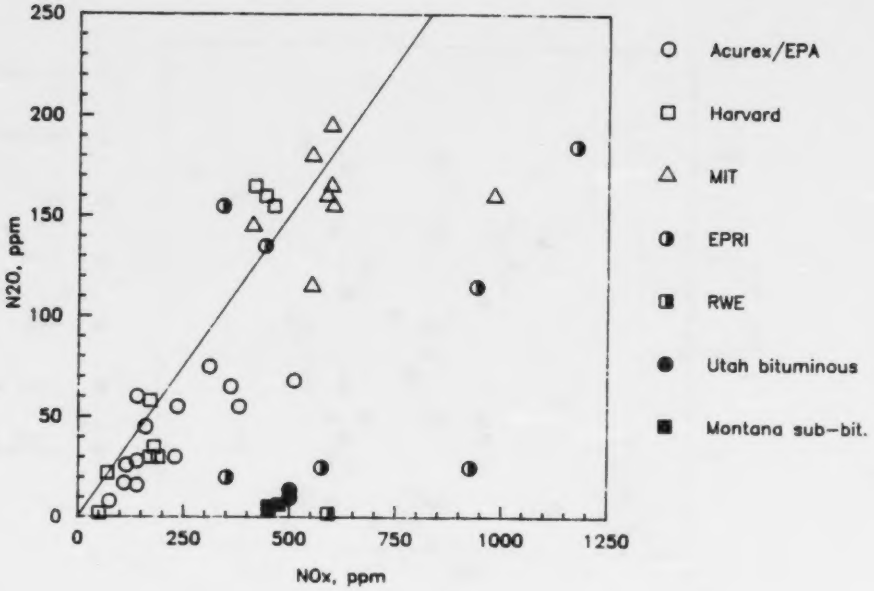

Figure 1. Existing N_2O/NO_x data from laboratory, pilot, and full-scale combustion systems presented at the EPA/NOAA/NASA/USDA N_2O Workshop.(5) Open and half-filled symbols represent historical data. The N_2O-N:NO_x correlation of Hao et al. (3) is presented. Fully filled symbols represent data taken by this group (and presented at the Workshop) burning two coals in a laboratory-scale combustor using an on-line GC/ECD sampling/analysis technique.

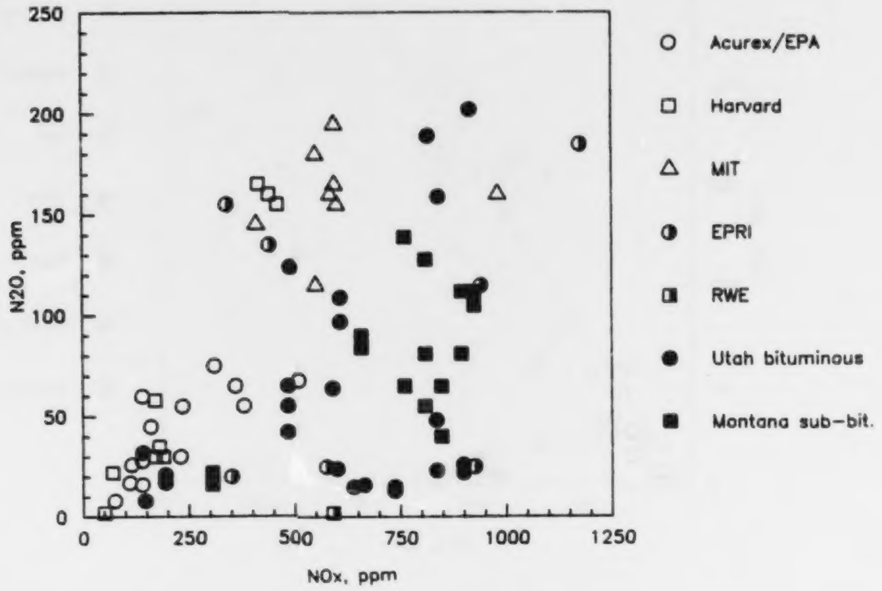

Figure 2. Existing N_2O/NO_x data as presented in Figure 1, compared to data taken by this group using an off-line sampling technique. Open and half-filled symbols represent historical data. Fully filled symbols represent data taken by this group burning the same two coals in the same combustor as presented in Figure 1 but using an off-line container sampling technique (refrigeration drying) with subsequent GC/ECD analysis.

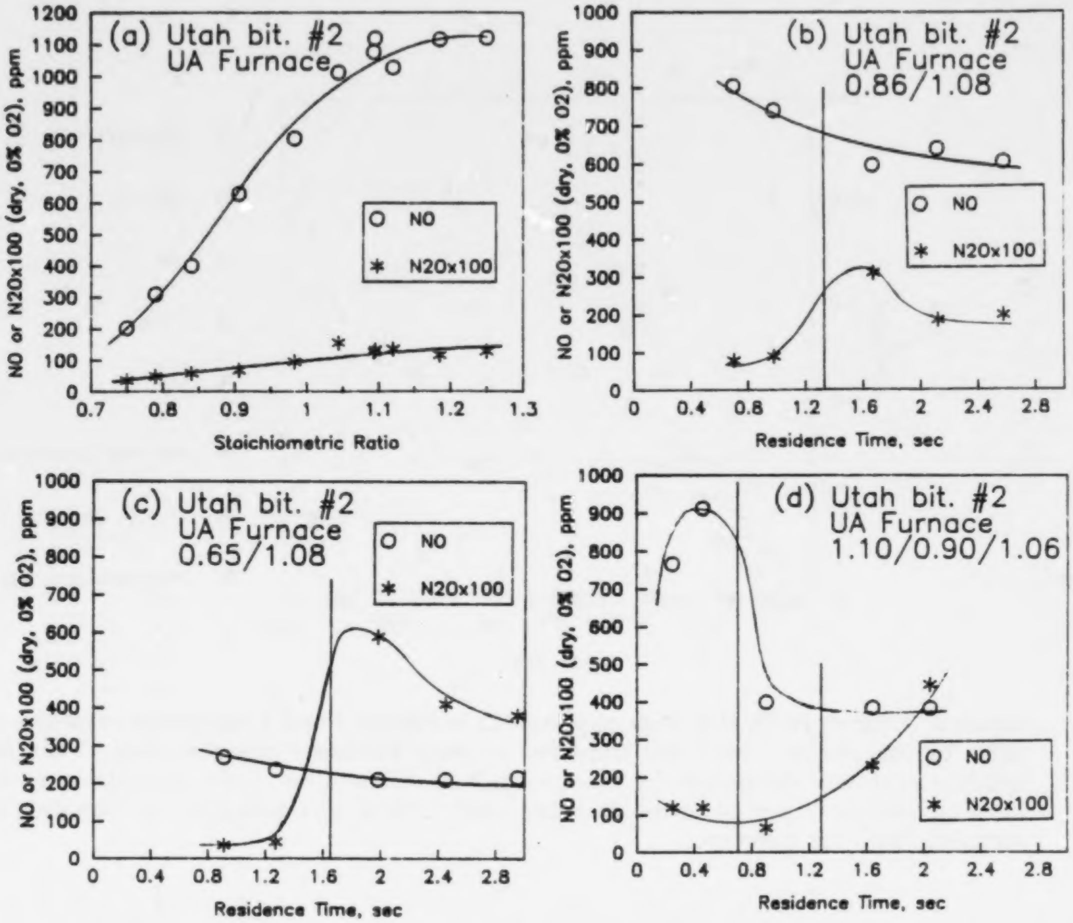

Figure 3. NO and N_2O concentrations from a laboratory-scale coal combustor as a function of (a) stoichiometric ratio (at combustor exhaust), and residence time using air staging (b) SR=0.86/1.08, (c) SR=0.65/1.08, and natural gas reburning (d) SR=1.10/0.90/1.06 strategies for NO_x control.

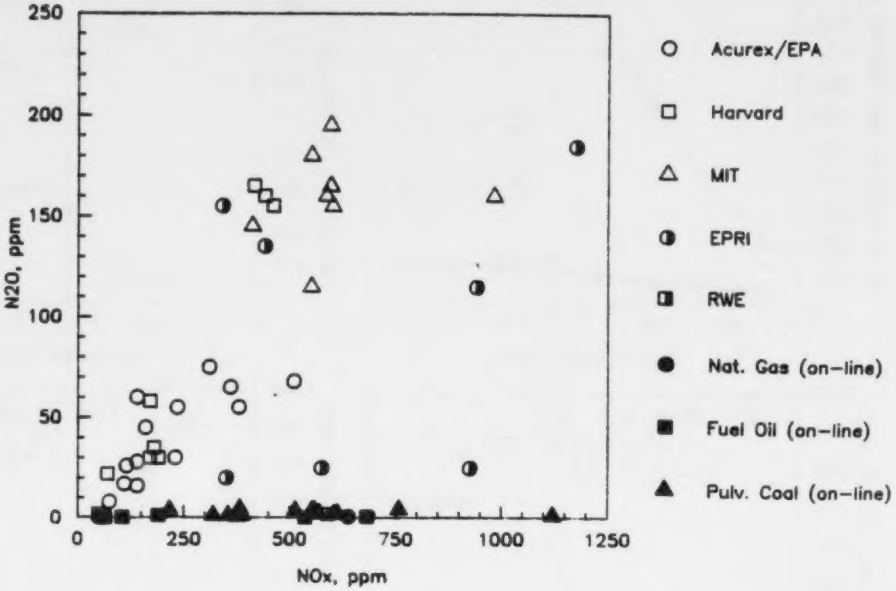

Figure 4. Existing N_2O/NO_x data as presented in Figures 1 and 2, compared to on-line data taken by this group. Open and half-filled symbols represent historical data. Fully filled symbols represent data taken by this group from full and sub-scale combustion systems burning several types of coals, fuel oils, and natural gas using an on-line GC/ECD sampling/analysis technique.

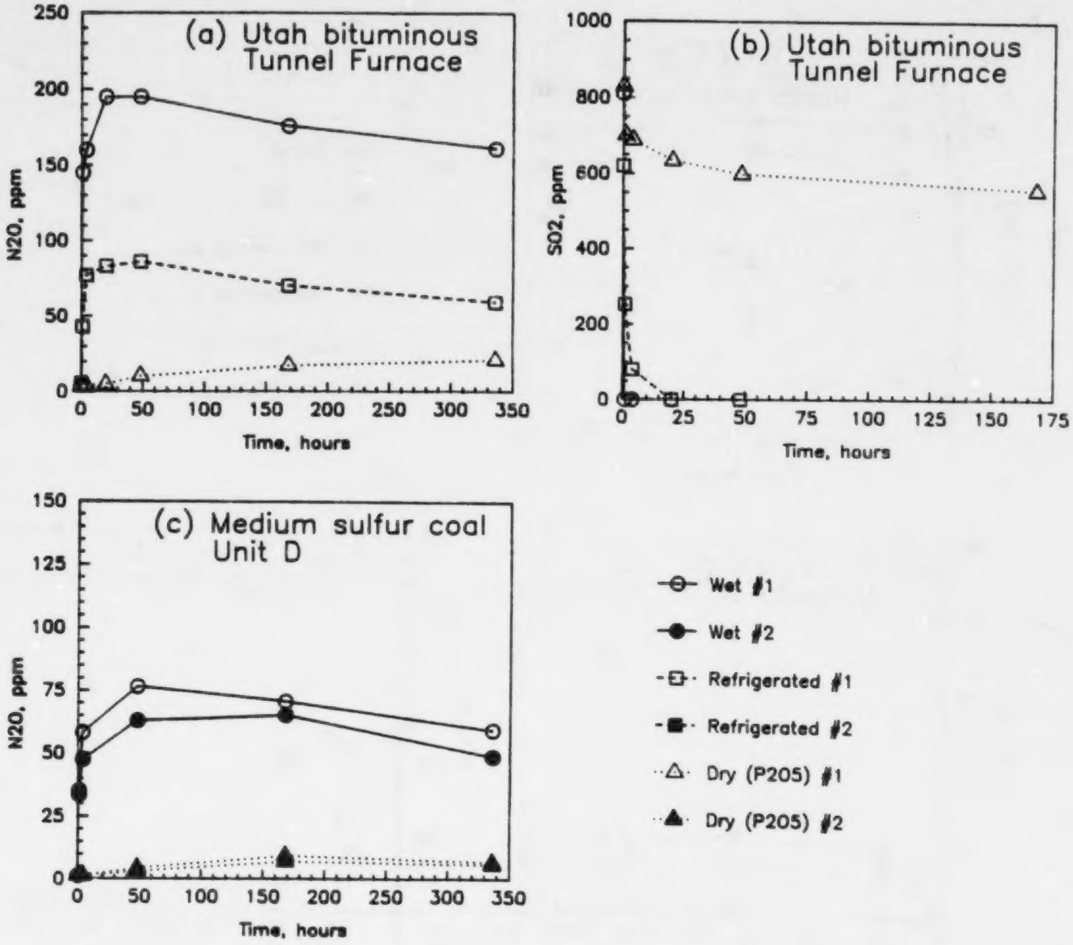

Figure 5. Evolution of N_2O and SO_2 with time from coal combustion samples collected and stored in stainless steel sampling containers at three degrees of sample dryness. Stack emission samples were collected using the (a, b) Downfired Tunnel Furnace burning Utah bituminous coal (SR = 1.42), NO(initial) = 757 ppm, and (c) Unit D (full-scale utility boiler) burning medium sulfur Alabama bituminous coal, NO(initial) = 354 ppm.

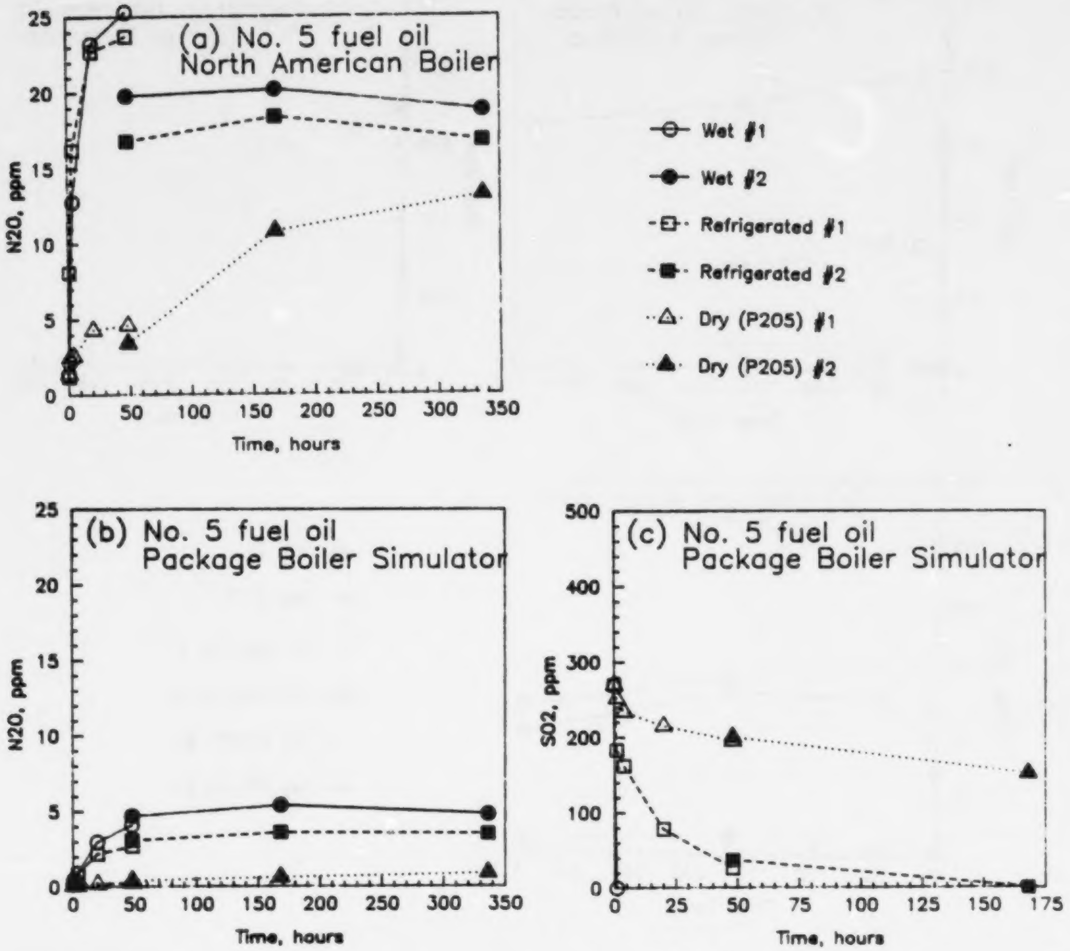

Figure 6. Evolution of N_2O and SO_2 with time from No. 5 fuel oil combustion samples collected and stored in stainless steel sampling containers at three degrees of sample dryness. Stack emission samples were collected using the (a) North American Boiler burning No. 5 fuel oil (SR = 1.25), NO(initial) = 189 ppm, and (b, c) Low NO_x Burner/Package Boiler Simulator burning No. 5 fuel oil (SR = 0.66/1.29), NO(initial) = 60 ppm.

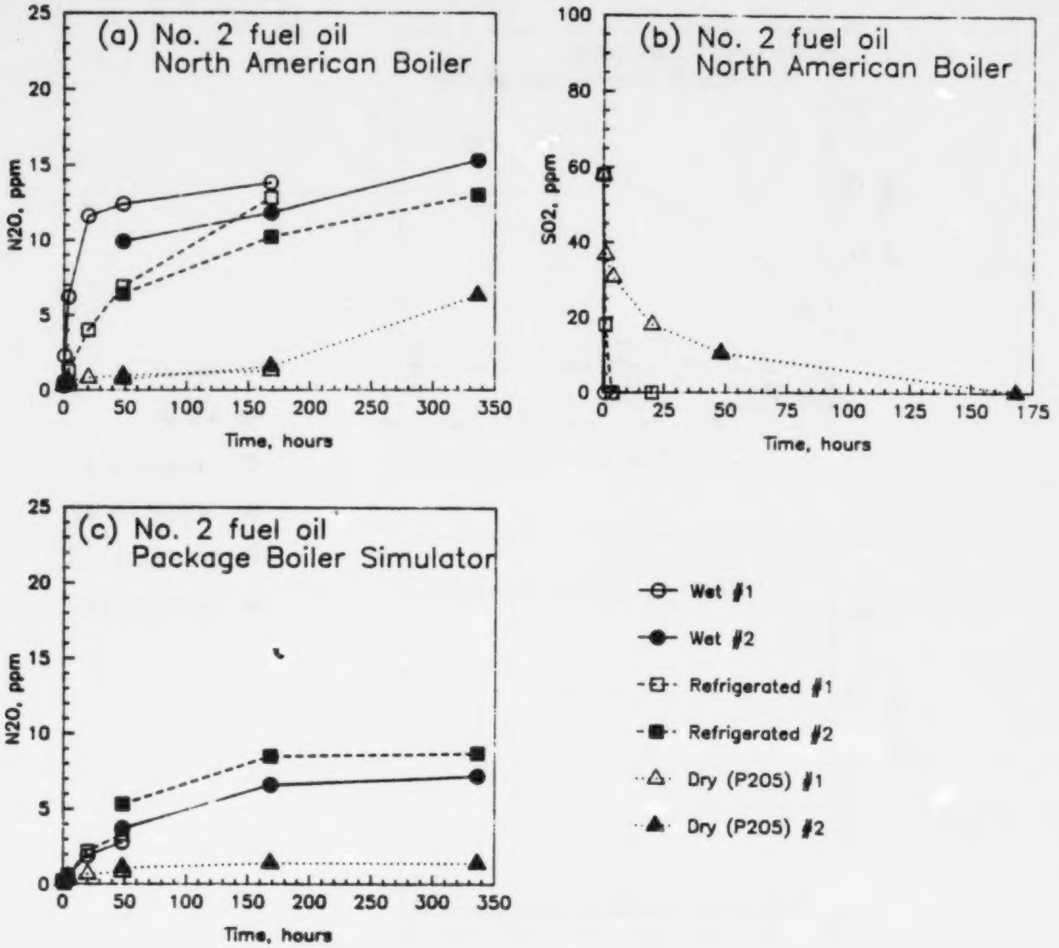

Figure 7. Evolution of N_2O and SO_2 with time from No. 2 fuel oil combustion samples collected and stored in stainless steel sampling containers at three degrees of sample dryness. Stack emission samples were collected using the (a, b) North American Boiler burning No. 2 fuel oil (SR = 1.25), NO(initial) = 105 ppm, and (c) Low NO_x Burner/Package Boiler Simulator burning No. 2 fuel oil (SR = 0.65/1.26), NO(initial) = 64 ppm.

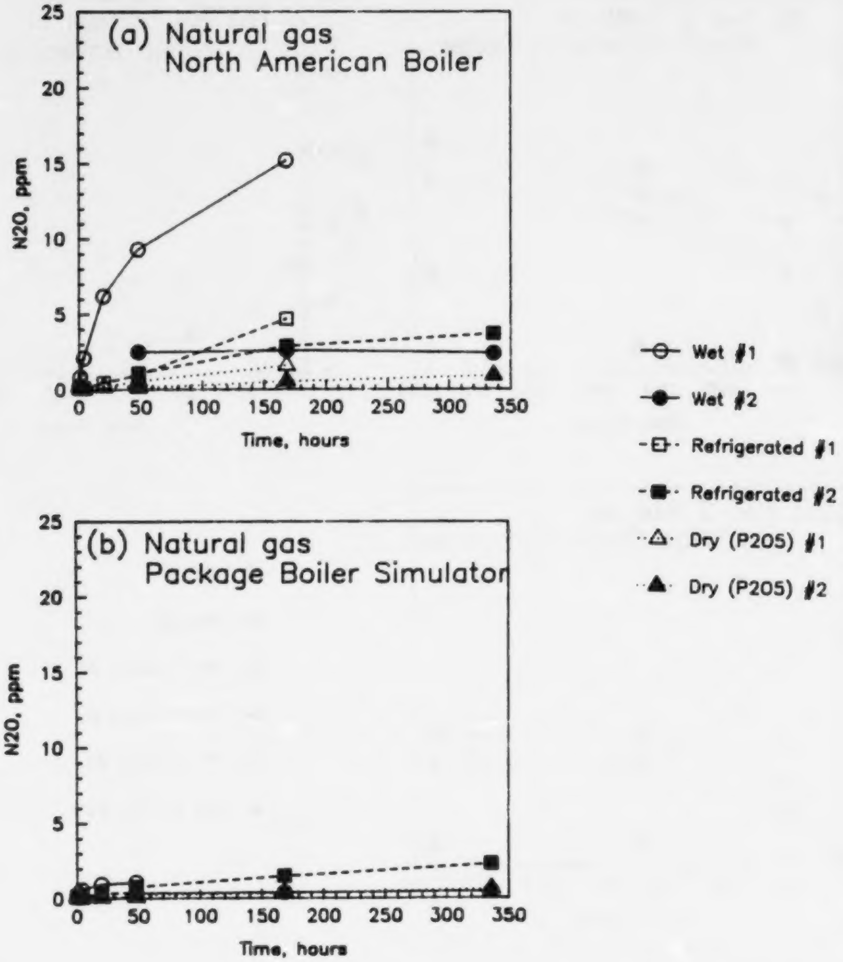

Figure 8. Evolution of N_2O and SO_2 with time from natural gas combustion samples collected and stored in stainless steel sampling containers at three degrees of sample dryness. Stack emission samples were collected using the (a) North American Boiler burning natural gas (SR = 1.24), NO(initial) = 62 ppm, and (b) Low NO_x Burner/Package Boiler Simulator burning natural gas (SR = 0.73/1.25), NO(initial) = 50 ppm.

Table 1

AVERAGE ON-LINE CONCENTRATIONS TAKEN FROM LABORATORY AND PILOT-SCALE COMBUSTION SYSTEMS*

Unit	Fuel	SR**	N_2O ppm	NO ppm	SO_2 ppm	CO ppm	O_2 %	CO_2 %
Tunnel Furnace	Utah bit. coal	1.42	4.2	757	753	17	5.5	13.9
Tunnel Furnace	Montana sub-bit. coal	1.43	2.2	613	380	30	5.3	14.6
Tunnel Furnace	Western Kentucky bit. coal	1.46	3.7	553	1650	12	6.8	12.6
Tunnel Furnace	Pittsburgh bit. coal	1.33	2.2	570	1450	-***	5.7	12.9
N. Amer. Boiler	Natural gas	1.24	<0.24	62	0	0	4.4	8.9
N. Amer. Boiler	No. 2 fuel oil	1.25	0.30	105	58	3	4.4	12.3
N. Amer. Boiler	No. 5 fuel oil	1.25	1.3	189	236	16	4.4	14.1
Low NO_x Burner/PBS****	Natural gas	0.73/1.25	<0.24	50	6	11	4.6	9.2
		1.10/1.25	0.72	638	4	14	4.6	8.7
Low NO_x Burner/PBS	No. 2 fuel oil	0.65/1.26	<0.24	64	130	2	6.1	12.0
		1.13/1.26	0.27	536	130	2	6.0	12.0
Low NO_x Burner/PBS	No. 5 fuel oil	0.66/1.29	0.26	60	270	25	5.4	12.2
		1.10/1.18	0.73	682	270	25	4.1	11.0
UA Coal***** Furnace	Utah bit. coal	1.25	1.28	1121	-	300	4.25	14.0
UA Coal Furnace	Utah bit. coal	0.65/1.08	1.99	605	-	400	3.60	14.3
UA Coal Furnace	Utah bit coal	0.86/1.08	3.80	216	-	500	3.50	14.8
UA Coal Furnace	Utah bit. coal	1.10/0.90 /1.06	4.45	382	-	400	3.85	13.8

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*All concentrations presented as measured (dry), no correction to constant percent O_2.

**Stoichiometric ratio.

***Missing data.

****Package Boiler Simulator.

*****UA data corrected to 0 percent O_2 (dry).

Table 2

AVERAGE ON-LINE CONCENTRATIONS TAKEN FROM FULL-SCALE UTILITY BOILERS*

Unit	Size MW	Class/Type**	N_2O ppm	NO ppm	SO_2 ppm	CO ppm	O_2 %	CO_2 %
A	250	Pre-NSPS Circular Babcock & Wilcox	1.3	386	-***	-	4.6	14.8
B	250	Pre-NSPS Triple Cell Babcock & Wilcox	<3.6	513	-	13.3	7.1	13.5
C	250	Pre-NSPS Circular Riley Stoker	<3.6	559	-	8.6	6.1	14.3
D	165	Pre-NSPS Tangential Combustion Engineering	<1.2	354	-	2.2	8.3	11.7
E	700	Pre-NSPS Tangential Combustion Engineering	0.7	374	-	30.7****	6.0	13.1
F	165	Pre-NSPS Tangential Combustion Engineering	<1.2	319	930	3.1	8.1	11.9

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*All concentrations presented as measured (dry), no correction to constant percent O_2.

**All units burned a medium-sulfur Alabama bituminous coal.

***Missing data.

****CO trace showed numerous spikes.

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MEASUREMENT OF N_2O FROM COMBUSTION SOURCES*

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ABSTRACT

N_2O emissions from fossil combustion have been reported to be 25-40% of the NO_X levels. At these levels, fossil fuels have been suggested to be a major anthropogenic source of N_2O. Recent tests have shown these measurements to be in error, the N_2O being formed by reaction between NO_X, SO_2, and H_2O in the sample containers. Time resolved measurements of gas samples stored in Tedlar bags, supported by chemical kinetic calculations, indicate that the majority of N_2O forms over a time period of 6 hours and depends on the amount of SO_2 present, initial NO level, and amount of water present.

A continuous infrared analyzer, suitable for characterizing N_2O from combustion sources, has been developed. The analyzer has been used to perform continuous on line N_2O measurements at nine utility boilers (pulverized coal and oil fired). The measurements indicate that the N_2O levels are generally less than 5 ppm and are not related to the NO_X levels in the flue gas.

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BACKGROUND

While global climate change has been associated with increased CO_2 levels in the atmosphere, concern is growing about the role of other trace gas species (CH_4, chlorofluorocarbons, carbon tetrachloride, N_2O, etc.). This paper addresses the measurement of nitrous oxide, N_2O, from combustion sources and the implications of these measurements on the potential role of combustion as a major anthropogenic source.

The mean global concentration of N_2O is approximately 300 ppb and has been increasing at a rate of 0.2-0.4 percent per year (1,2). In the troposphere, N_2O, is a relatively strong absorber of infrared radiation, and can contribute to the Greenhouse Effect. Being stable in the troposphere, N_2O is transported to the stratosphere. In the stratosphere N_2O is the largest source of stratospheric NO and the major natural chemical sink establishing the stratospheric O_3 concentration (3).

The increase of N_2O in the atmosphere has been attributed to anthropogenic sources, although the dominant man-made source of N_2O is still uncertain. Weiss (2), Hao et al. (4), and Tirpak (1) suggest that combustion of fossil fuels results in emissions of N_2O that can account for the observed increase in N_2O. Previous N_2O measurements from combustion sources indicate that systems fired with natural gas do not produce significant concentrations of N_2O. However, substantial levels of N_2O were reported from systems fired with residual oil or coals (e.g., fuels containing nitrogen and sulfur). In fact, the measurements of Hao et al. (4) and Castaldini et al. (5) suggest that the N_2O emissions are related to the emissions of NO_X (NO + NO_2); the N_2O level being 25-40 percent of the NO_X concentration. Global N_2O production from combustion sources has been calculated using the relationship between N_2O and NO_X coupled with known NO_X emissions from combustion. Thus it is important to accurately establish this N_2O/NO_X ratio.

The N_2O measurements from combustion sources have primarily been made by gas chromatographic analysis of gas samples collected in glass or stainless steel containers. Recent measurements have shown that these grab samples can undergo chemical reaction in the containers creating N_2O concentrations substantially higher than those originally formed in the combustion process (6, 7). A sampling "artifact" exists, as a result, the N_2O measured can exceed the actual emission. This paper will: 1) discuss this artifact including experimental observations and a proposed chemical mechanism, 2) propose measures to minimize this artifact, 4) discuss the development of a continuous N_2O analyzer, and 5) discuss representative emission levels of N_2O from practical coal-combustion measured with the continuous N_2O analyzer.

GRAB SAMPLE N_2O MEASUREMENT ERROR

The artifact in measuring N_2O with grab sampling techniques was initially identified in the course of combustion experiments in a down-fired gas, bench-scale tunnel furnace. A description of the furnace is available elsewhere (8). Gas samples were withdrawn with a water-cooled, stainless steel probe and introduced directly into 1000 ml Pyrex sample flasks. The flasks were subsequently analyzed for N_2O by gas chromatography with electron capture detection (9).

During a set of experiments with the gas fired combustion tunnel, NH_3 was doped into the fuel to increase NO_x levels, and SO_2 was doped into the primary burner air. Grab samples from this experiment showed approximately 300 ppm N_2O. This finding was surprising since N_2O concentrations above 10 ppm have not been reported in natural gas flames. Further experiments determined that the high N_2O concentrations were associated with the SO_2; if SO_2 was absent from the reactants, the exhaust N_2O concentrations were 2-3 ppm, consistent with previous results.

Further combustor tests showed that the N_2O was being formed in the sample flasks through a reaction mechanism involving SO_2, NO, and H_2O (6, 7). To verify this reaction mechanism, Pyrex containers (250 ml) were filled with simulated flue gas mixtures: N_2, 86.2%; O_2, 4.3%; CO_2, 9.4%; and NO, 600 ppm. One milliliter of water was placed in the container to simulate the condensed water from the combustion products. For selected samples, the pH of the added liquid was adjusted to various values by the addition of sulfuric acid (this simulated the collection of combustion generated SO_3 into the condensate). In each case, the filled sample containers were allowed to age for approximately 2 hours before analysis. The samples were then analyzed for N_2O in the same manner as the sample flasks from the combustion experiment. Figure 1 illustrates results from four of these tests. In the first, no SO_2 was introduced into the gas-phase, and only distilled water was added for the liquid phase. No N_2O was observed in the container. Likewise, the N_2O yields were insignificant when the 1.0 ml liquid phase was acidified with H_2SO_4 to a pH of 1.6. However when 1500 ppm SO_2 was added to the gas-phase, significant N_2O was measured in the container, with the liquid phase being either distilled water or H_2SO_4 (pH 0.6).

The presence of SO_2 is a necessary condition for the formation of N_2O within the container. The influence of SO_2 concentration was tested by repeating the combustion experiment described above with varying amounts of SO_2 introduced into the primary air and collecting the sample in either 1 liter glass flasks or 270 liter Tedlar bags. The N_2O analysis results shown in Figure 2 (7) indicate that values of SO_2 below 500-600 ppm lead to only a minor amount of N_2O formation. Above 600 ppm, however, significant amounts of N_2O are generated. Since SO_2 concentrations vary considerably between various fossil fuel sources, the severity of container-formed N_2O may also vary between the sources. The reader should note that the quantitative aspects of this conclusion may change depending on initial condition in the container (e.g., O_2, NO, amount of condensate).

Additional tests were performed to better quantify the progress of the reactions occurring in the sample flasks. Specifically, tests were conducted to determine the time history of N_2O, NO, NO_2, and SO_2 in the sample containers. Gas samples from the natural gas fired combustor were collected in 270 liter Tedlar bags and subsequently analyzed for NO, NO_2, N_2O, and SO_2. The 270 liter Tedlar bags provided sufficient sample to allow samples to be withdrawn and analyzed as a function of time using continuous gas analyzers. (N_2O was analyzed with the continuous analyzer described in a subsequent section of this paper.)

The primary variable for the test series was SO_2 concentration, which was varied from 710 ppm to 2500 ppm. The time histories of N_2O, NO_X, and SO_2 are shown in Figure 3. As can be seen in Figure 3a, the majority of the N_2O formation occurs in the first six hours irrespective of the initial SO_2 level. The accompanying time histories of NO_X and SO_2 are shown in Figures 3b and 3c. As seen in Figures 3a-c, at the high SO_2 condition, virtually all of the NO_X initially present in the Tedlar bag shows up as N_2O in the final product. At the lowest SO_2 test condition (716 ppm), N_2O continues to form until virtually all of the SO_2 is removed from the gas phase, after which the N_2O stabilizes while the NO_X continues to decrease. At the intermediate SO_2 level (1210 ppm), the N_2O formation rate is initially rapid becoming more gradual after 2 hours, as the NO_X and SO_2 are consumed. For this intermediate case, there appears to be sufficient SO_2 to allow the reaction to proceed longer than at the low SO_2 condition, but not sufficient SO_2 to convert all of the initial NO_X to N_2O, as at the higher SO_2 levels.

CHEMICAL KINETICS

The gas phase and aqueous reactions between SO_2, NO_X, and H_2O leading to the formation of N_2O have been documented in the literature. Martin et al. (10) discuss the reaction mechanism and the general chemistry has also been discussed in the wet FGD scrubbing literature (11, 12).

Lyon and Cole (13) proposed the detailed mechanism, shown in Table 1. An overall path based on this mechanism is shown in Figure 4. In the sample flasks, the NO is oxidized to NO_2. NO_2 and SO_2 in the gas phase are taken to be in equilibrium with the aqueous phase. In the aqueous phase, the NO_2 and SO_2 ultimately form N_2O and H_2SO_4 through a reaction sequence involving HNO.

The detailed mechanism was integrated for the same conditions as the experiments conducted in the Tedlar bags (Figure 3). The results of these calculations are compared to the experimental results in Figure 5a-c. In general, the agreement between the model and the experiments is good. The characteristic time for N_2O formation is basically the same between experiment and model, with the experiment exhibiting somewhat faster N_2O formation than predicted by the model. However, there are three noteworthy differences between the experiments and the model calculations. First, for the medium and high SO_2 cases, the kinetics under predict the amount of N_2O formed. At the high SO_2 condition the experiments exhibited virtually 100% conversion of the NO_X to N_2O, whereas the model predicts 65% conversion of the NO_X to N_2O. Second, in the Tedlar bags the rate of disappearance of NO_X decreased as the SO_2 level decreased. Whereas the kinetic calculations indicate little effect of SO_2 level upon the NO_X time histories. Thirdly, the experiments show an SO_2 threshold for N_2O formation (Figure 2) whereas the calculations indicate a fairly linear dependence of N_2O formation with SO_2 concentration. The threshold with SO_2 appears in the calculations if the amount of condensed water is increased.

In spite of the differences, the initial calculations suggest that the mechanisms shown in Table 1 provide a reasonably good representation of the N_2O formation in the sample flasks.

SAMPLING TECHNIQUES TO MINIMIZE N_2O FORMATION

In light of the potential formation of N_2O in grab samples from combustion systems, a question arises as to which sampling protocols can lead to valid N_2O measurements. The results presented in Figure 3 indicate that N_2O is formed in the sample flasks over a time period of 1-6 hours. Thus, one approach to obtain valid samples would be to perform the N_2O analysis on-line, avoiding storage of the samples.

On-line N_2O analysis may not always be available, or warranted, for an initial characterization of a combustion system. In these cases, it is appropriate to establish, and utilize, a grab sampling technique capable of obtaining valid N_2O samples from combustion systems. The results discussed previously indicate that the conditions leading to N_2O formation in the sample flasks require the presence of 1) condensed H_2O, 2) SO_2, 3) NO, and 4) a low pH resulting from the aqueous reactions between SO_2 and NO_X.

Three sampling methodologies have been investigated as possible approaches for obtaining valid grab samples (7). Each method focuses on eliminating one or more of the requirements necessary for N_2O formation in the sample containers:

1. drying the sample: eliminates the aqueous phase
2. removing SO_2 ahead of the sample flask: eliminates one of the key species needed to form N_2O
3. altering the pH of the aqueous phase: raises the pH to interfere with the chemical mechanism leading to N_2O formation in the flasks

In the tests reported by Muzio et al. (7), sampling approaches 2 and 3 (outlined above) have been shown to produce valid grab samples for N_2O. Drying the gas sample through an ice bath to a 0 - 1°C dew point does not appear to adequately condition the sample. With 750 ppm of initial NO_X and 2500 ppm of SO_2, the dried sample produced 26-40 ppm of N_2O, whereas methods removing the SO_2 or altering the pH yielded N_2O levels less than 3 ppm.

CONTINUOUS N_2O ANALYZER DEVELOPMENT

Under EPRI funding, the UCI Combustion Laboratory has been actively engaged in a research program to develop a continuous N_2O analyzer suitable for on-line measurements from combustion sources. Development of the continuous N_2O analyzer was initiated prior to discovery of the artifact in the grab sampling measurement technique. With the high levels of N_2O reported from coal fired utility boilers, it was felt that a continuous N_2O analyzer was necessary to better characterize N_2O emissions. The discovery of the artifact in the grab sampling method increased the necessity for an on-line technique for valid N_2O measurements. The goal has been to establish a measurement technique which 1) has minimal interferences, 2) is relatively simple, compact, reliable, and 3) suitable for both field and laboratory use. A previous paper outlined the requirements and criteria for a continuous analyzer utilizing infrared absorption for measuring N_2O in combustion effluent (14). The key points from this study include:

1. The 7.8 micron region in the infrared is most suitable for measuring N_2O in combustion products.
2. At 7.8 microns, the primary interfering species are SO_2 and NO_2.
3. SO_2 and NO_2 can be readily removed from the sample stream ahead of the analyzer without affecting N_2O levels.

Based on the criteria listed above, a field prototype instrument has been designed and built in cooperation with HORIBA, Ltd. The analyzer is a nondispersive infrared analyzer utilizing a 500 mm sample cell. A schematic of the analyzer is shown in Figure 6. Replaceable optical filters allow the instrument to measure N_2O either in the optical region around 4.5 microns, or 7.8-8.5 microns. To date, the 7.8-8.5 micron region has been used. To minimize interferences, the analyzer uses two Luft-type detectors in series. The first, or primary detector, senses N_2O and any interfering gases that absorb in the 7.8-8.5 micron region. Since the first detector absorbs all of the radiation from the N_2O bands, the radiation reaching the second detector is only that due to interfering species. The second detector then senses the interfering species and electronically compensates for their effect.

The initial specifications for the analyzer included two ranges: 0 to 250 ppm and 0 to 500 ppm. This specification was made at the time N_2O concentrations up to 400 ppm were anticipated to be emitted from coal fired systems. However, the analyzer is capable of operating on a 0 to 25 ppm full scale range with sufficient signal to noise ratio to detect 0.5 ppm changes in N_2O level.

Simulated combustion products were used for the initial evaluation of the prototype continuous N_2O analyzer. High purity gases were blended to 1) verify the linearity of the instrument, 2) quantify the extent of interferences from CO_2, CO, NO, NO_2, and SO_2, and 3) verify the capability of removing NO_2 and SO_2 from the sample stream without affecting N_2O levels.

The analyzer responds linearly to N_2O concentrations ranging between 0 and 250 ppm, as well as between 0 and 25 ppm. As previously indicated, the analyzer has sufficient signal to noise ratio to detect a 0.5 ppm change while operating with a range of 0 - 25 ppm, full scale.

Subsequently, the extent of the interferences produced by typical coal combustion products was evaluated. Interference curves were generated for CO levels between 0 and 500 ppm; CO_2, 0 and 20 %; NO, 0 and 1250 ppm; SO_2, 0 and 4000 ppm. The interference curves generated are shown in Figure 7. In general, the results agree with the previous study, SO_2 is the primary interfering species (14). The analyzer utilized some construction materials that adsorb NO_2, which precluded generation of an interference curve for this species.

Because of the NO_2 adsorption within the analyzer and the extent of SO_2 interferences, provision for NO_2 and SO_2 removal from the sample stream ahead of the analyzer is included in the measurement system. Previous work demonstrated that NO_2 and SO_2 could be scrubbed from the gas sample without affecting the N_2O (14). The SO_2 and NO_2 are removed using sodium carbonate and sodium sulfite solutions, respectively. These results were verified with the prototype analyzer.

FIELD APPLICATION

After completing the initial laboratory evaluation and validation, the analyzer was used to make continuous N_2O measurements in utility boiler combustion flue gases. To date, N_2O measurements have been made at nine sites. Table 2 briefly describes each unit tested (manufacturer, firing configuration, fuel, and rated load) and summarizes the NO_X and N_2O emissions from each unit under its normal operating conditions. As seen in Table 2, direct N_2O emissions from utility boilers firing either oil or pulverized coal are low and not a substantial fraction of the NO_X emissions. In fact, the N_2O emissions are generally less than 5 ppm. As seen in Table 2, at two of the units, the N_2O analyzer showed levels of 6 and 11 ppm. These levels are likely due to the sampling system and not necessarily a consequence of the combustion process. At each site, the N_2O analyzer system was integrated into an existing continuous gas analysis system, consequently the sampling system varied from site to site. As explained below, depending on the configuration of the system, N_2O can potentially form in the sample lines.

Evidence of sample line generated N_2O has been found with the continuous analyzer. At one of the sites, several unheated sample lines were used in the sampling system. Typically all of the sample lines were not in use at the same time; several of the lines were dormant while a specific sample (or set of sample lines) was being monitored. The dormant lines contained condensed water and residual SO_2 and NO from the flue gas. Figure 8 is a duplication of a strip chart trace recorded during a particular test at this site. The arrows indicate when a change was made from one group of samples lines being monitored to another, a sharp peak in N_2O level can be seen. These peaks can be attributed to N_2O formation in the dormant sample lines. Once the line has been flushed completely with "new" sample, the N_2O levels decrease and remain constant. Since substantial N_2O formation occurred in the dormant sample lines, the measured levels under steady-state conditions may have also included a small amount of N_2O generated in the sample lines to the analyzer.

At units A and B, grab samples were also obtained and analyzed for N_2O. Grab samples were obtained with NaOH in the flask to inhibit N_2O formation. As seen in Table 3, the N_2O levels of the grab samples were in good agreement with the values obtained with the continuous analyzer (a gas chromatograph with helium ionization detector was used for the grab sample analyses, the lower detectability limit of this system is 2 ppm).

CONCLUSIONS

The following conclusions can be drawn from the results discussed above:

- N_2O measurements using grab sampling techniques are subject to errors due to reactions between NO, SO_2, and H_2O forming N_2O in the sample containers.
- Formation of N_2O in grab samples can be inhibited by either scrubbing the SO_2 from the flue gas ahead of the sample flask or altering the aqueous pH of the sample by adding NaOH to the container prior to use.
- The continuous analyzer system designed and built for the detection of N_2O is capable of N_2O analysis in combustion effluents at levels down to a few ppm.
- Use of the continuous analyzer at nine utility boilers indicates that direct N_2O emissions are low (generally, less than 5 ppm), and that the N_2O levels are not a substantial fraction of the NO_x levels as previously suggested.

ACKNOWLEDGEMENTS

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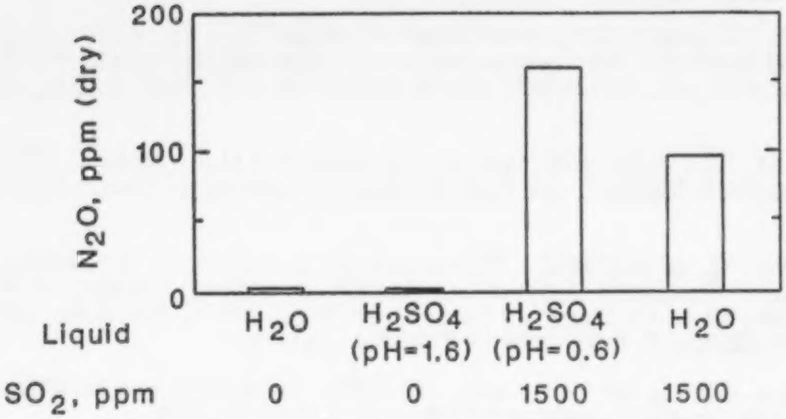


Figure 1. Concentration of N_2O within the 250 ml sampling containers after 2 hours with artificial combustion products (N_2, O_2, CO_2), 600 ppm NO, and 1 ml of liquid (6) (Copyrighted by, and used by courtesy of, the American Geophysical Union.)

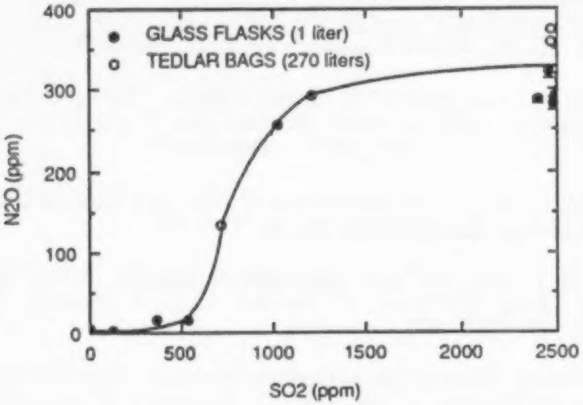


Figure 2. Influence of furnace SO_2 Concentration on N_2O observed within the sampling containers.

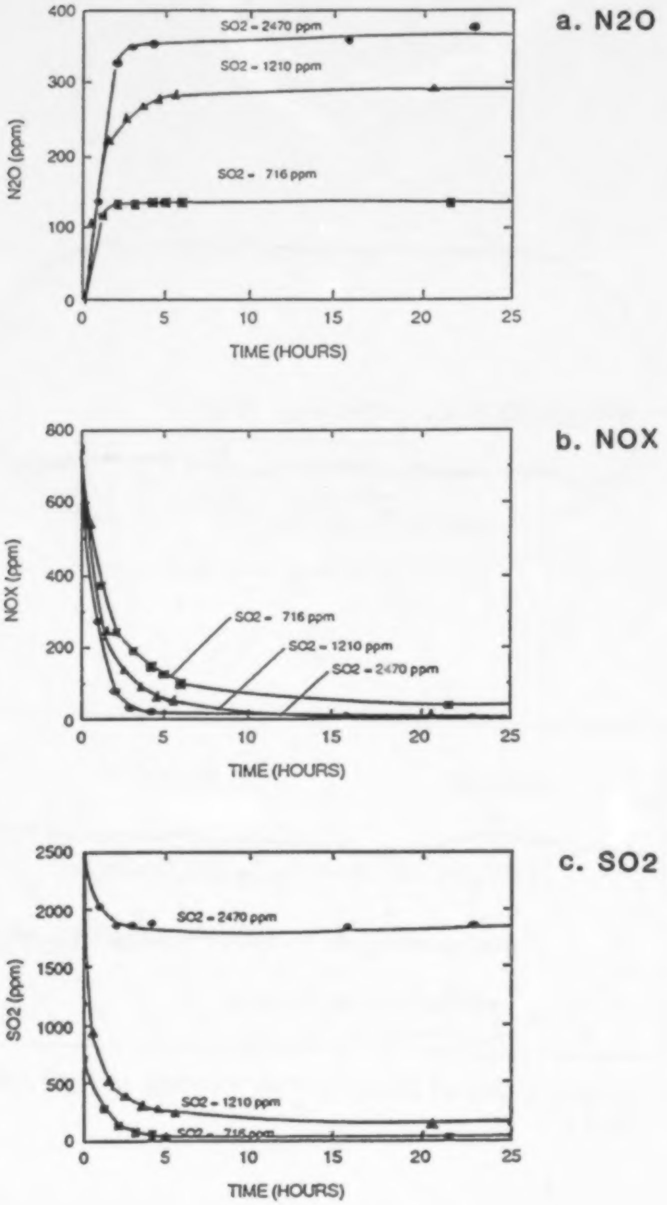


Figure 3. Time Histories of N_2O, NO_X, and SO_2 during Reaction in 270 liter Tedlar Bags: Experimental Results
(a. N_2O, b. NO_X, c. SO_2)

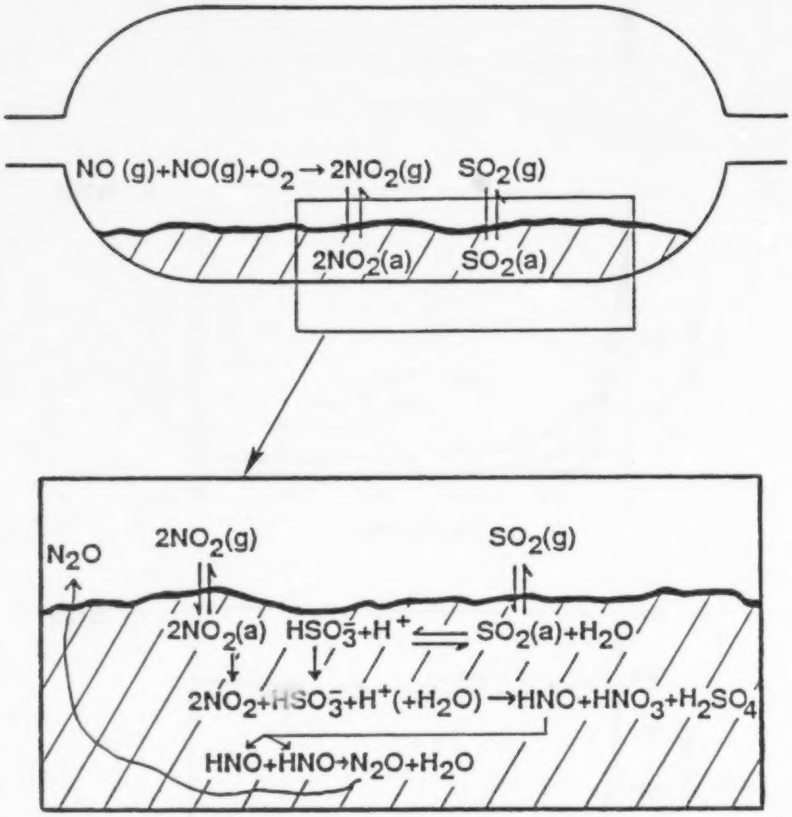
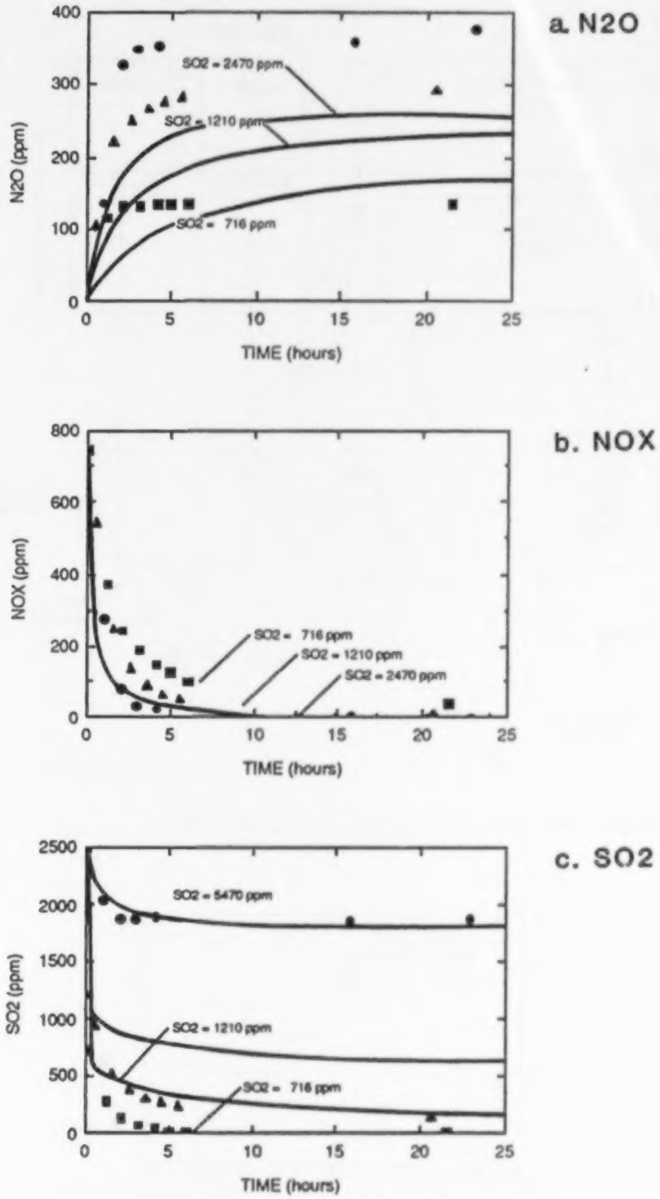

$NO(g)+NO(g)+O_2 \rightarrow 2NO_2(g)$
$SO_2(g)$
$2NO_2(a)$
$SO_2(a)$
N_2O
$2NO_2(g)$
$SO_2(g)$
$2NO_2(a)$
$HSO_3^- + H^+ \rightleftharpoons SO_2(a)+H_2O$
$2NO_2+HSO_3^-+H^+(+H_2O) \rightarrow HNO+HNO_3+H_2SO_4$
$HNO+HNO \rightarrow N_2O+H_2O$

Figure 4. Possible Overall Chemical Path Leading to N_2O Formation in the Sample Flasks (7)



a. N2O

b. NOX

c. SO2

Figure 5. Time Histories of N_2O, NO_X, and SO_2 during Reaction in 270 liter Tedlar Bags: Experimental versus Model Results (a. N2O, b. NOX, c. SO2)

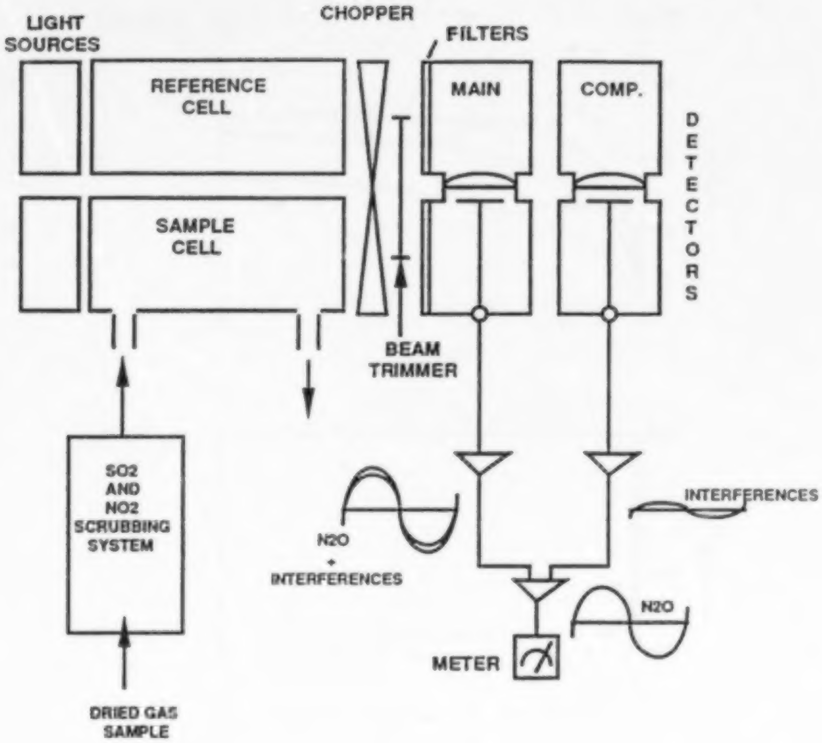

LIGHT SOURCES
CHOPPER
FILTERS
REFERENCE CELL
MAIN
COMP.
DETECTORS
SAMPLE CELL
BEAM TRIMMER
SO2 AND NO2 SCRUBBING SYSTEM
DRIED GAS SAMPLE
N2O + INTERFERENCES
INTERFERENCES
N2O
METER

Figure 6. Field Prototype N_2O Analyzer Schematic

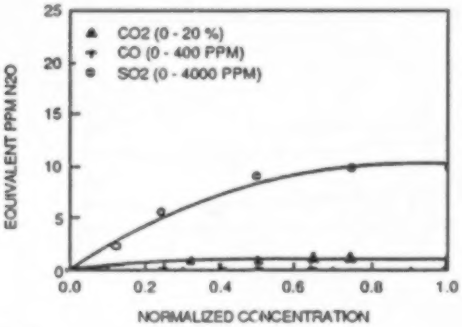


Figure 7. N_2O Analyzer Evaluation: Interferences (without SO_2 and NO_2 Scrubbing System)

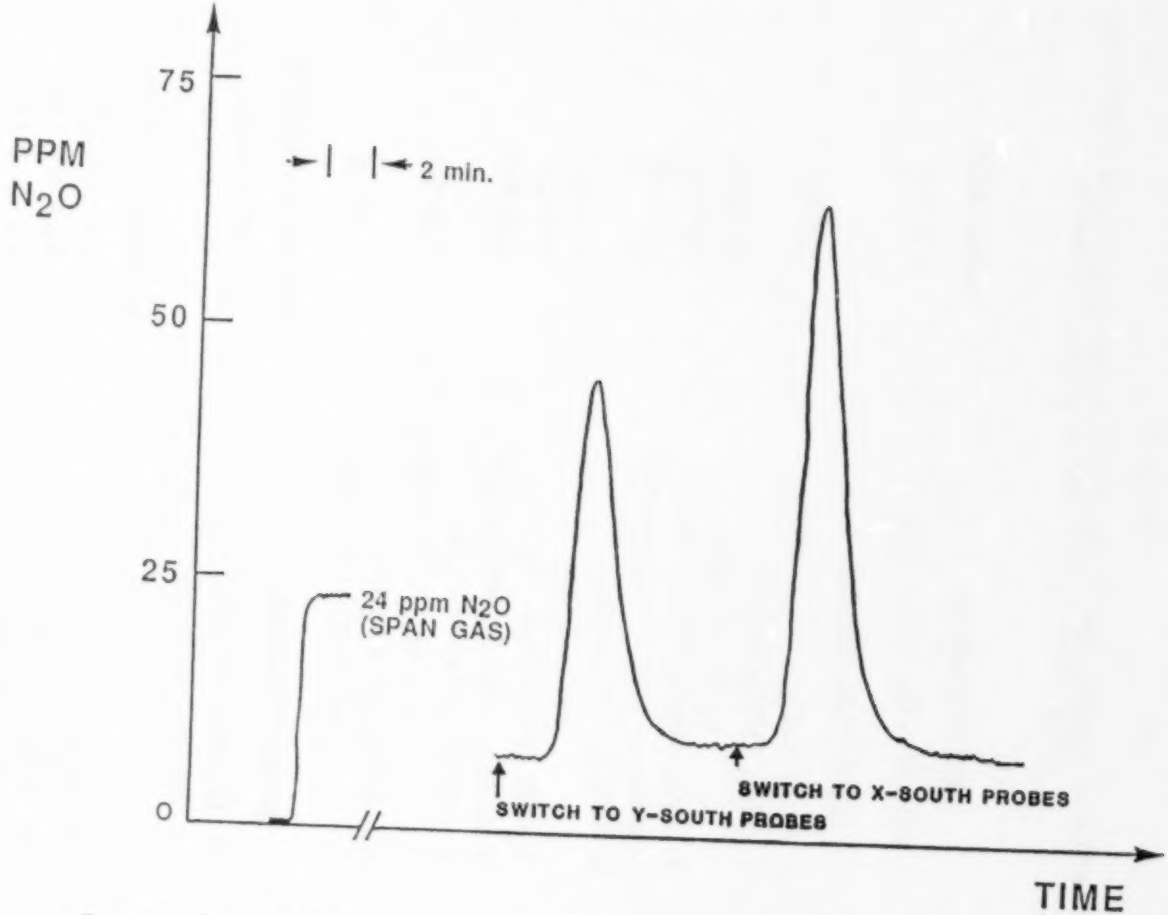


Figure 8. Strip Chart Trace demonstrating N_2O formation in Dormant Sample Lines

Table 1.

Chemical Mechanism, Rate Constants and Equilibrium Constants at 25°C (13)
(Rate constants are in units of L/mol/s or $L^2/mol^2/s$)

Gas Phase Reaction	Rate Constant
1. $NO + NO + O_2 = NO_2 + NO_2$	6.73 E+3
Liquid Phase Reactions	
2. $NO_2 + HSO_3^- = NO_2^- + HSO_3$	3.00 E+5
3. $HSO_3 + HSO_3 (+H_2O) = H_2SO_3 + H_2SO_4$	5.00 E+5
4. $2NO_2 + H_2O = HNO_2 + HNO_3$	7.00 E+7
5. $HNO_2 + HSO_3^- = NOSO_3^- + H_2O$	2.40 E+0
6. $NOSO_3^- + H^+ (+H_2O) = HNO + H_2SO_4$	5.00 E+1
7. $HNO + HNO = N_2O + H_2O$	3.00 E+4
8. $NOSO_3^- + HSO_3^- + HNO(SO_3)^{2-}$	8.50 E+1
9. $HNO(SO_3)^{2-} + H^+(+H_2O) = HONHSO_3^- + H^+ +HSO_4^-$	1.90 E-2
10. $HNO(SO_3)^{2-} + H_2O = HONHSO_3^- + H^+ + HSO_4^-$	1.50 E-6
Equilibrium Processes	Henry's Law Constants
11. $NO_2(gas) = NO_2(aq)$	H = 0.01 M/atm
12. $SO_2(gas) = SO_2(aq)$	H = 1.30 M/atm
	Equilibrium Constants
13. $SO_2(aq) = H^+ + HSO_3^-$	K = 1.54 E-2 M
14. $HNO_2 = H^+ + NO_2$-	K = 5.10 E-4 M
15. $HSO_4^- = H^+ SO_4^{2-}$	K = 1.20 E-2 M

Table 2.

N_2O Emissions from Utility Boilers

UNIT	DESIGN TYPE	Fuel	LOAD RATED (MW)	LOAD TEST (MW)	Continuous Emission Data O_2 %	NOx PPM @ 3% O_2	N_2O PPM @ 3% O_2
A	Foster Wheeler ● horizontally-opposed	coal	620	600	3.5	982	11**
B	Combustion Engineering ● tangentially-fired	coal	790	750	5.2	325	<1
C	Combustion Engineering ● tangentially-fired	coal	790	650	5.7	390	<1
D	Babcock and Wilcox ● opposed-fired	coal	280	270	7.0	692	6
E	Riley-Stoker ● horizontally-opposed	coal	280	270	6.0	662	2
F	Combustion Engineering ● tangentially-fired	coal	180	90	8.3	498	1
G	Combustion Engineering ● tangentially-fired	coal	790	542	6.0	393	1
H	Babcock and Wilcox ● face-fired	oil	215	215	5.4	268	<1
I	Babcock and Wilcox ● face-fired	oil	115	90	3.3	268	1

** THE SAMPLE CONFIGURATION MAY HAVE LED TO N_2O FORMATION IN THE SAMPLE LINES

Table 3.

N_2O Measurement Method Comparison: Grab Sample versus Continuous Analyzer

UNIT	DESIGN TYPE	Fuel	LOAD RATED (MW)	LOAD TEST (MW)	CONTINUOUS O_2 %	CONTINUOUS N_2O PPM @ 3% O_2	GRAB SAMPLES N_2O PPM @ 3% O_2
A	Foster Wheeler ● horizontally-opposed	coal	620	500 380	3.5 4.4	8 9	5 10,12
B	Combustion Engineering ● tangentially-fired	coal	790	750	5.2	<1	<2

* 2 ppm is the detectibility limit; grab samples obtained with flasks containing NaOH

Session 2

COMBUSTION NO_x DEVELOPMENTS I

Chairman: D. Eskinazi, EPRI

The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

The application of combustion modifications for NO_x-reduction to low rank coal fired boilers

by

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ABSTRACT

Stringent environmental control regulations in the Federal Republic of Germany aim for the NO_x-emission from large combustion equipment not to exeed 200 mg/m^3 of dry flue gas (about 100 ppm) as daily average values, in general. This goal is expected to be reached by the end of 1989 for all utility boilers with a capacity of 300 MW_{th} and larger.

Due to the fact that the properties of the coals in Germany differ distinctly from those fired in other countries a direct application of the limited experience with large scale NO_x-reduction techniques gained elsewhere was not possible. Therefore, a large number of research and development projects were initiated in the last 5 years throughout the Republic which concentrated mainly on the two areas, namely selective catalytic reduction (SCR) in the flue gases and modifications to the combustion system. By these activities it has been found that the application of combustion modifications is an economically interesting alternative.

Up to now brown coal fired boilers with an electrical capacity of more than 7000 MW in total were successfully retrofitted with various combinations of combustion modifications.

The paper deals with the development of the NO_x-reduction techniques for large coal fired utility boilers, describes the solutions applied, and presents the results reached so far in boiler operation.

1. INTRODUCTION

The last two decades are characterized by a growing concern of the public about the quality of our environment. This obvious tendency is in particular emphazised by the increasing indications of negative effects of manmade emissions on human health, fauna, flora and even on our nonliving surrounding like e.g. stone and concrete buildings.

This general understanding lead in the past to legal actions in various highly industrialized countries in order to limit the discharge of i. a. noxious gases from stationary and mobile sources. The consequence was that industry either had to choose for alternatives with reduced emission potential or - as occured in the majority of the cases - was forced to install removal and/or conversion techniques to reduce the discharge of harmful species.

The combustion of fossil fuels and their derivatives, as being one of the important processes for the generation of secondary/tertiary energy, is also a producer of various noxious gas compounds depending on the fuel used. Among these gases, the oxides of nitrogen (NO_x) are believed to play a major role in the acid rain formation. Therefore, the NO_x-emission is restricted by law in many countries already.

In the Federal Republic of Germany a general limitation of the emission of noxious gases from stationary sources with a capacity of larger than 50 MW_{th} took effect in 1983 by the introduction of the large furnace order. Additional restrictions were set by a resolution of the state ministers for Environmental Affairs in April 1984, which were further tightened by local agreements e.g. in the State of Northrhine Westfalia. Table 1 shows the permissible values. Today only the values given under 3 (right) are valid and have to be applied to both new and existing installations. These values must not be exeeded in daily average. In addition, 97 % of the half hour average values have to be below the 1.2fold and all of these must not exeed the 2fold of the values quoted. With these conditions the German NO_x-emission standards are at present the most stringent regulation with regard to either the actual permitted emission values, the short integration times for reporting, or the capacity and age of the installations concerned.

2. REDUCTION OF NO_x-EMISSIONS

For the reduction of the NO_x-emission from combustion systems there are, in principle, four groups of options available:

- NO_x can be removed from flue gases by the selective catalytic reduction (SCR) technique with the addition of ammonia (NH_3) resulting in the harmless gases molecular nitrogen (N_2) and water vapour(H_2O). This technique has been introduced on large scale into the power industry in Japan and Germany.

- Also, wet chemical cleaning can reduce the NO_x-concentrations in the flue gases. Several principles are offered the majority of which remove NO_x and SO_x in combination. Most of these options are still under development and large scale experience is hardly availabe at present.

- There are various selective non catalytic reduction (SNCR) processes available, in which the NO-reduction is caused by the reaction with N-H or C-H based chemicals. These materials are injected into the combustion chamber at certain temperature levels. Various large scale demonstrations are known from the USA from Japan and - more recently - also from Germany.

- Finally the NO_x-emission can be diminished by the application of several modifications to the combustion system. The effect of these technical alternations can be twofold namely either lowering the production of nitrogen oxides in the early stages of combustion or destroying once formed NO during the burn out phase of the fuel. In general, both phenomena cannot be hardly distinguished. Combustion modifications were proven to be the first option of NO_x-removal to be considered and numerous applications are known worldwide. However, so far only limited removal efficiencies have been reported and a combination with the earlier mentioned options e.g. with SCR is necessary in order to comply with very low limiting values like those valid in the Federal Republic of Germany.

Only recently a substantial increase of NO_x-removal efficiency has been reached by combining different combustion modifications, in particular, for low rank coals. For such a fuel, the German brown coal, the principles applied and the results obtained will be described in the following chapters.

3. PRINCIPLES OF NO_x-REDUCTION DURING COMBUSTION

The base for the application of all combustion modifications is the knowledge of the most important influencing parameters.

With regard to the origin of the nitrogen it is known that the mechanisms of NO_x-production are temperature dependent and that at least for the common dry bottom coal firing systems the source for more than 95 % of the emitted NO_x is the fuel-bound nitrogen.

Apart from temperature the accessibility of the fuel nitrogen to oxygen is an important parameter which, in turn, is governed by the local availability of the oxygen and of the N-containing species.

Although at present not all of the fairly complicated mechanisms involved are fully clarified a simplyfied scheme of the fate of fuel nitrogen during combustion can help to understand the various options for diminishing NO_x, figure 1. On heat treatment by either combustion or external sources the fuel-N can be partly liberated with the released volatiles and can be found e.g. in the stable species NH_3 and HCN with the rest remaining in the char. Both types of nitrogen species - gaseous and solid - will be eventually converted into NO under oxygen-rich conditions. An oxygen-lean surrounding, however, offers the possibility for conversion into molecular nitrogen. Also, once formed NO can be converted into N_2 by the introduction of various reducing partners. As already mentioned in chapter 2 and as indicated in figure 1 different species can be utilized.

From this scheme it can be deduced that the following alternations to the combustion process should result in lowering the NO_x-emission:

- reduce overall oxygen level,
- diminish local oxygen accessibility,
- add oxygen stagewise,
- reduce temperature, in general,
- avoid extreme temperature peaks,
- favour formation of NO-reducing species, or
- add NO-reducing species at adequate flue gas conditions.

Consequently, a low NO_x-combustion system could be described by the following steps, figure 2: After ignition, a pyrolysis zone should support the liberation of volatile nitrogenous species. As next step an oxygen-lean combustion zone will produce flue gas with a low NO_x-concentration. This region has to be followed by the burnout zone in order to complete the combustion reaction. If necessary, NO_x-reducing species could be also introduced at appropriate temperature levels.

4. RESULTS FROM UTILTIY BOILERS

After the introduction of the large furnace order the Rheinisch-Westfälisches Elektrizitätswerk AG (RWE), with more than 26000 MWe the largest utility in the Federal Republic, was considering various options for the NO_x-removal, in particular, for the boilers based on Rhinisch brown coal. The total capacity of these units is 9300 MWe with single boiler sizes ranging from 75 to 600 MWe.

The Rhinisch brown coal differs distinctly from other fossil fuels, e.g. bituminous coals or lignites. A high moisture level of 55 - 62 % on raw coal basis, a variable ash content of 2 - 20 %, and a low nitrogen concentration of 0.3 - 0,4 % are typical for this fuel.

Consequently brown coal combustion requires specifically designed fuel preparation circuits and boilers which in conjunction with the fuel properties result in specific flue gas conditions. The flue gas contains about 20 % water vapour resulting in maximum flame temperatures below 1200 °C and fairly constant NO_x-concentrations well below 800 mg/m^3 (approx. 400 ppm).

After detailed investigations of the SCR-technique and first successful trials with alternations to the combustion chamber in research rigs and also in prototype boilers already in 1984, RWE decided to retrofit all brown coal fired units with combustion modifications only.

Based on the principles given in the previous chapter various technical solutions were tested and lead to the following combustion modifications:

The most simple method, namely a **reduction of the overall excess air level** showed in short tests for both coal fired boilers and research rigs the expected results (fig. 3), namely a lowering of the NO_x-emission by about 60 - 80 mg/m^3 (approx 30 - 40 ppmv) for the O_2-range investigated regardless of the boiler capacity. However, the general application of an excess air level reduction is boiler and fuel dependent and may be limited due to the dangers of reduced burn out, slagging, fouling, and corrosion.

Apart from reducing the overall excess air level a decrease of the local stoichiometry at the burner will also have a positive effect on the NO_x-emission. By this principle, known as **air staging**, the air/fuel-ratio at the burner face can be reduced to values of 0,8 - 0,9. The remaining combustion air is introduced as burn out air into the downstream area of the combustion chamber via one or more levels of additional ports. For this reason air staging is often called over fire air (ofa) technique. The principle of air staging is widely applied to single burners by splitting the secondary air flow and also to the combustion chamber.

As an example for the application of this technique fig. 4 shows the retrofit arrangement for a 300 MWe boiler with 2 levels of air staging. Fig. 5 gives some results gained with this arrangement. It can be clearly seen that air staging through the upper level of air ports is more effective for NO_x-reduction than through the lower ports. This clearly shows that an early air injection results in again enhancing the deliberately delayed combustion by the lowered stoichiometry at the burner. In this way the retarded NO_x-formation in the flame root is shadowed by an additional NO_x-production in areas where still unreacted fuel is found.

As mentioned earlier the major goal of air staging is the reduction of the stoichiometry at the burner in order to minimize the change for NO_x-production provided that sufficient oxygen is still available to ensure stable ignition of the fuel. Secondly the intended production of gaseous N-containing species in an oxygen lean envrionment is promoted which favours the conversion to harmless molecular nitrogen. In fig. 6 air staging tests in different boilers burning a variety of coals are expressed as a function of the important primary burner zone stoichiometry. The data show the expected tendency; the scatter is due to the parameters of the test.

The results given in fig. 5 have also indirectly shown that sufficient residence time is required for the combustion before the final air through the staging ports should be added. In particular, for retrofit situations this may be a vital condition and can be met by concentrating the fuel inlet in the lower part of the combustion chamber. The effect on the NO_x-emission can be clearly seen from fig. 7, when for a 600 MWe boiler (fig. 4) the original 6 fuel injection levels are reduced down to 4 and 3 levels by closing the upper ports and still keeping full load operation. This **shortening of the burner hight** also leads indirectly to an additional reduction of the O_2-level at the burner by increasing the local fuel concentration. This again is positive because it further lowers the potential for NO_x-formation in the flame root and also enhances the already mentioned production of gaseous nitrogenous species in a oxygen-deficient surrounding, thus improving the chance for NO-conversion to N_2.

In addition, fig. 7 shows that also with a high concentration of fuel (only 3 injection levels in operation) air staging can further improve the NO_x-reduction.

As an important result of the above described combination of excess air level reduction, shortening of the burner belt area and air staging fig. 7 also clearly reveals that the envisaged goal for the final NO_x-emission of 200 mg/m^3 (approx. 100 ppmv) can be reached for this fuel by a certain combination of combustion modifications only.

The NO_x-reducing effect can be further emphasized by **recirculation of flue gases** from downstream of the fly ash precipitator into the combustion chamber. This can be realized by either mixing with the combustion air or injecting the flue gas as separate jets directly into the boiler. This principle reduces the local oxygen accessibility by dilution and may also lower the local temperature. In addition - in the case of separate injection -, the jet momentum is favourable for the mixing of the retarded low NO_x combustion process in order to counteract the residence time increase and, hence, reduce the danger of higher burn out losses. Also it is assumed that the low O_2-content of the flue gas jets may be favourable in oxygen lean regions prior to the injection of the final staged air in order to reduce excessive CO, a consequence of the delayed combustion and a potential problem for operation and environment.

In fig. 8 the effect of flue gas recirculation is shown for 4 already partly converted boilers of different type and capacity. Although the NO_x start values differ in some cases the enhanced NO_x-reduction with increasing the amount of recirculated flue gases is obvious. Also noticible is that the recirculation effect helps to reach emission values below the envisaged 200 mg/m^3.

Another possibility for creating an oxygen-lean primary zone in the vicinity of the burner mouth is the separation of the fuel/gas mixture leaving the mill into a fuel-rich portion which enters through the burner and a remaining fuel-lean portion which can be injected through additional ports into the oxygen-poor combustion zone. Apart from supporting the fuel pyrolysis close to the burner the downstream injection of the fuel-lean portion will result in similar effects to those expected from the flue gas recirculation. If this principle, often called **bruden separation**, is combined with some of the previously described combustion modifications also NO_x-emissions below 200 mg/m^3 can be reached.

The following figures 9 - 12 show typical examples of boilers retrofitted to meet a final NO_x emission of 200 mg/m^3 or less. To date - end of 1988 - 25 brown coal fired boilers with a total capacity of 7200 MWe are already converted, the remaining 2100 MWe will follow before the end of 1989. Fig. 13 summarized the results achieved so far. From these data it is obvious that a low NO_x-emission can be reached by various combinations of modifications. The choice for a particular combination has to be made individually in each retrofit situation dependent on local conditions and economic considerations.

5. EFFECTS ON PLANT PERFORMANCE

Assessing the combustion modifications it has to be taken into account that due to the retardation of the combustion process ignition problems and, in particular, unburnt carbon losses may occur, which could also cause malfunction of the electrostatic precipitator.

Often a steep rise of the CO-concentration of the flue gas can be observed when lowering the oxygen level, figure 14. This, in turn, may also result in major operational problems like deposit formation and corrosion. For bituminous coal fired boilers it is known that high CO- (and H_2S-) concentrations in an O_2-lean surrounding at or near the heat transfer surfaces may give rise to material wastage.

Finally it should be noted, that when operating a flue gas desulfurisation scrubber behind the boiler the change of O_2 in the flue gas should be considered. Also any increase in flue gas exit temperature could cause problems with the connecting ducts.

Therefore, when utilizing combustion modifications various negative side effects on plant performance could occur. This may limit the application of the otherwise economically attractive way for reducing the emission of nitrogen oxides with the consequence of reconsidering also other more expensive options in order to fulfil the requirements of existing emission standards.

		1 after July 1, 88	2 as early as possible	3 after Dec 31,89
brown coal		1000	200	200
bitum. coal	dry bottom	1300	200	200
	wet bottom	2 000	200	200
oil		700	150	150
gas		500	100	100

1 Large furnace order (1 July 1983)

2 Resolution by the state ministers of environmental affairs (5 April 1984)

3 Agreement between gouvernment and utilities in the State of Northrhine-Westfalia (November 1984)

Table 1: Permissible NO_x-emission for existing units > 300 MW_{th} in the Federal Republik of Germany (values in mg/m³ in dry flue gas at 6 % O_2; for ppm on volume basis devide by 2,05)

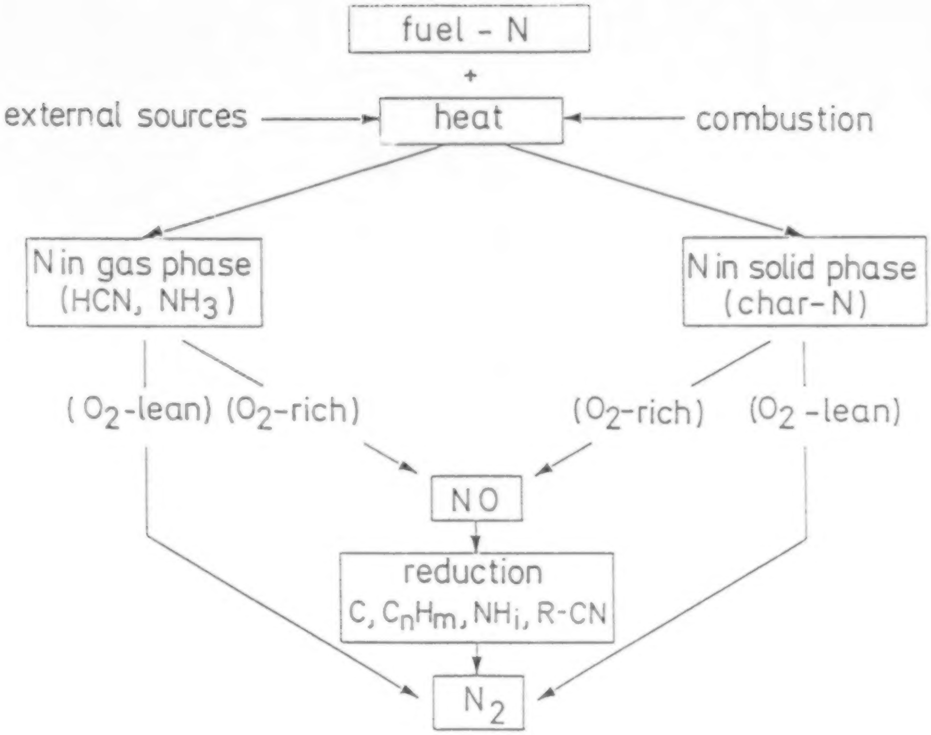

fuel - N
+
external sources
heat
combustion
N in gas phase (HCN, NH3)
N in solid phase (char-N)
(O2-lean)
(O2-rich)
(O2-rich)
(O2 -lean)
NO
reduction
C, CnHm, NHi, R-CN
N2

Fig. 1: Conversion of fuel-N in coal combustion (simplified scheme)

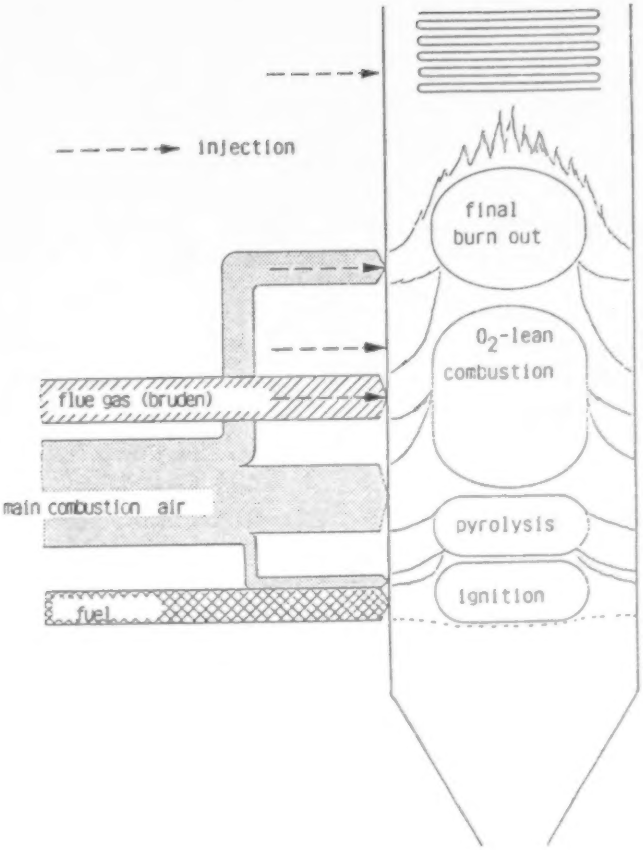

injection
final burn out
O_2-lean combustion
flue gas (bruden)
main combustion air
pyrolysis
ignition
fuel

Fig. 2: Low NO_x-combustion (scheme)

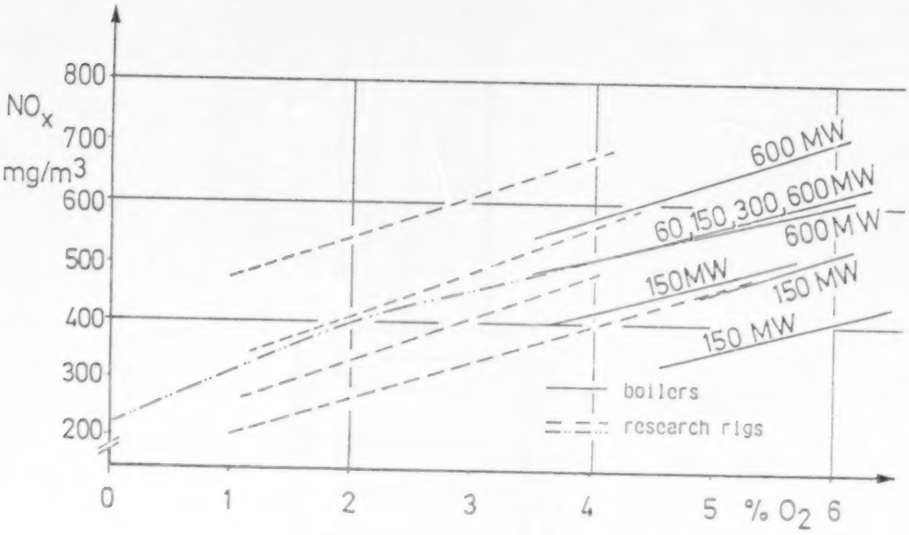


Fig. 3: NO$_x$-emission as function of excess air level, (expressed as oxygen content upstream of the preheater)

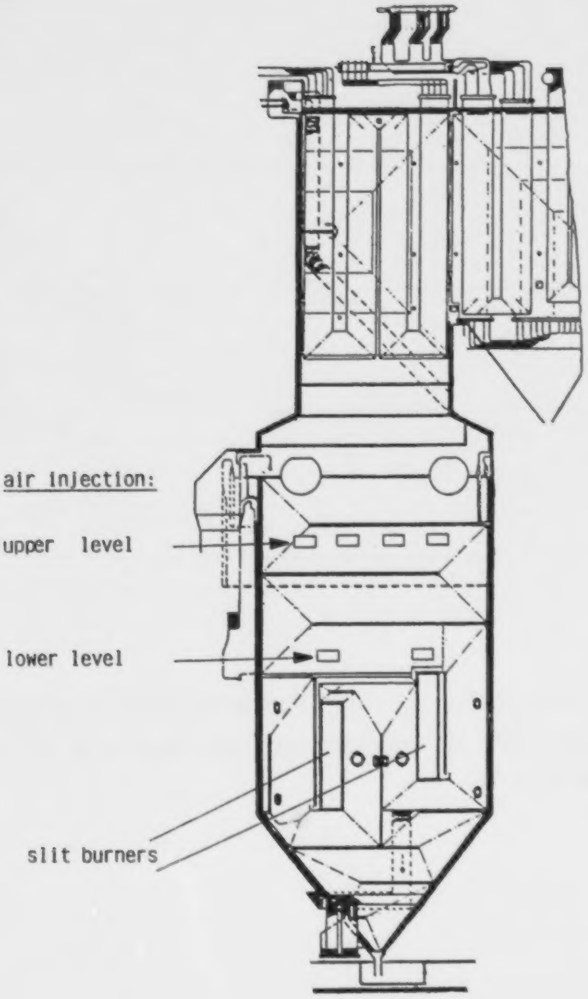

air injection:
upper level
lower level
slit burners

Fig. 4: The principle of air staging
(300 MWe, example)

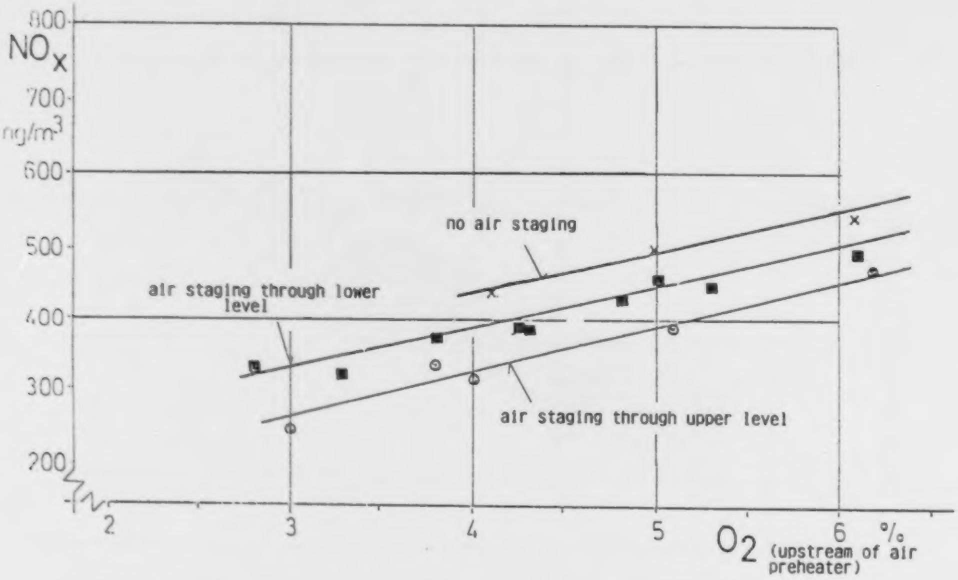


Fig. 5: Effect of air staging
(300 MWe, approx. 20 % of total air through staging ports)

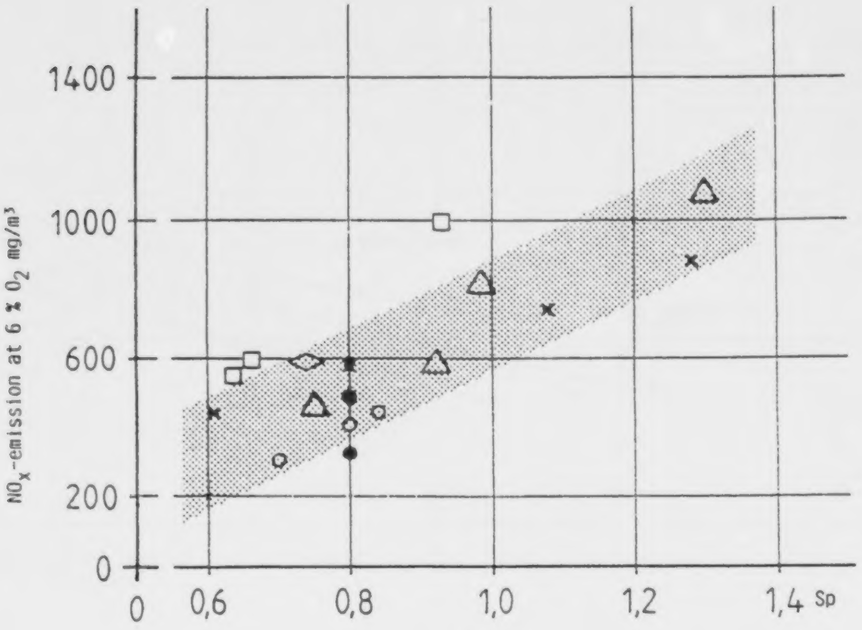


Fig. 6: Effect of primary zone stoichiometry Sp

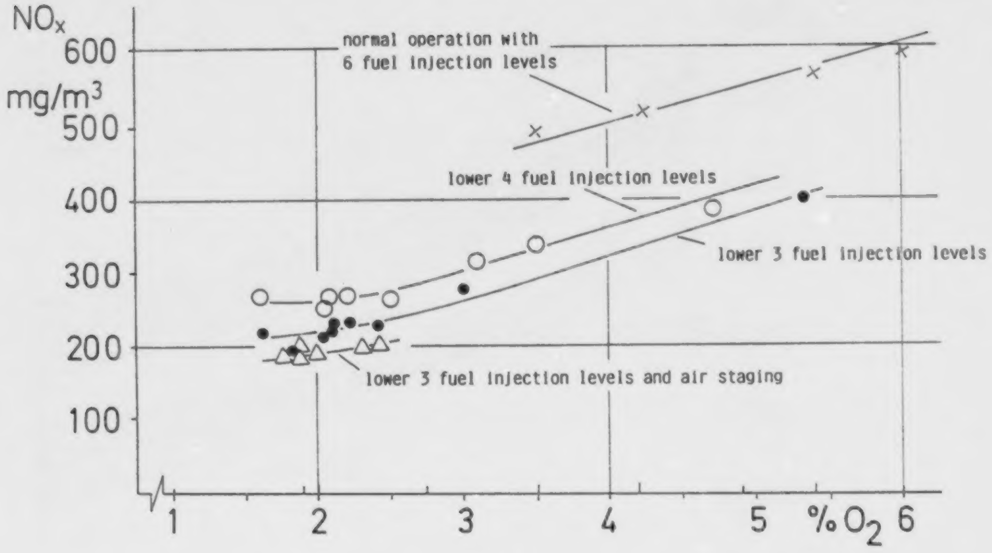


Fig. 7: Effect of fuel concentration by shortening of the burner belt area

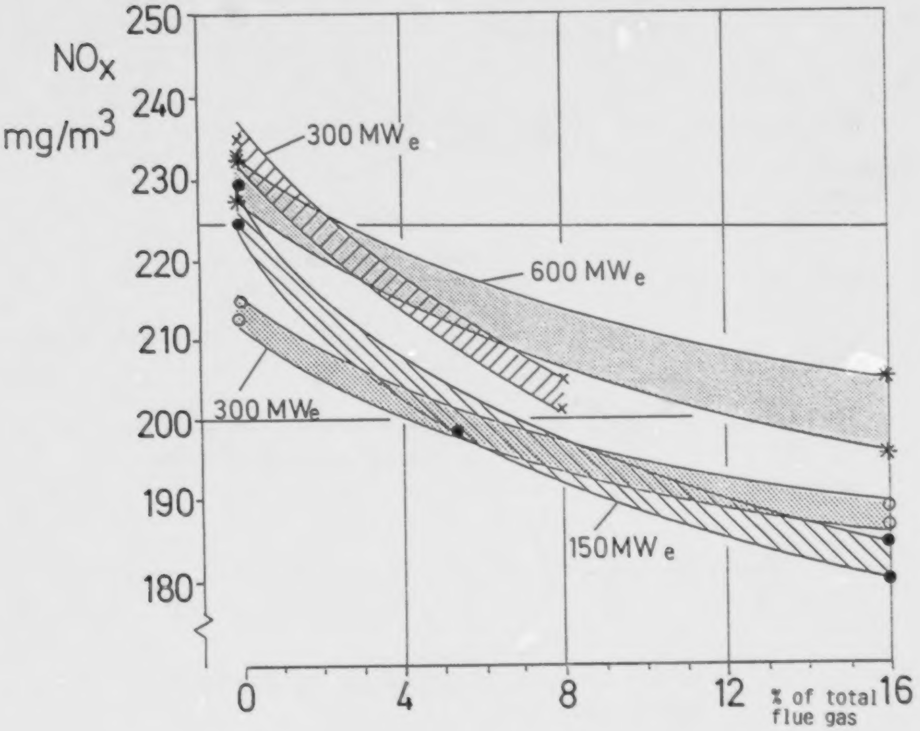
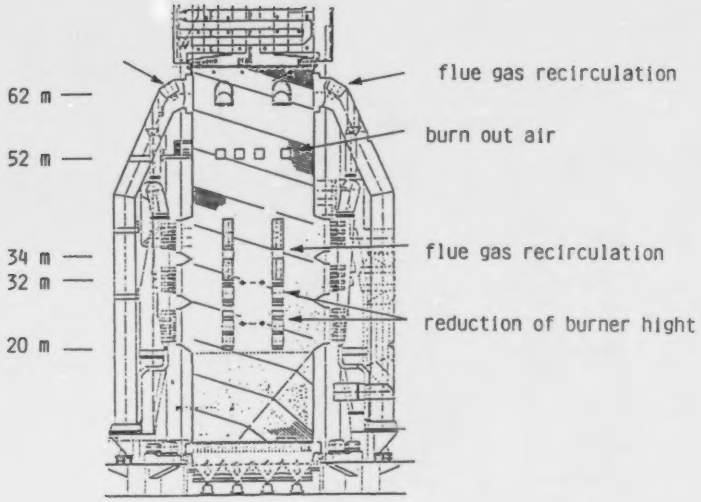


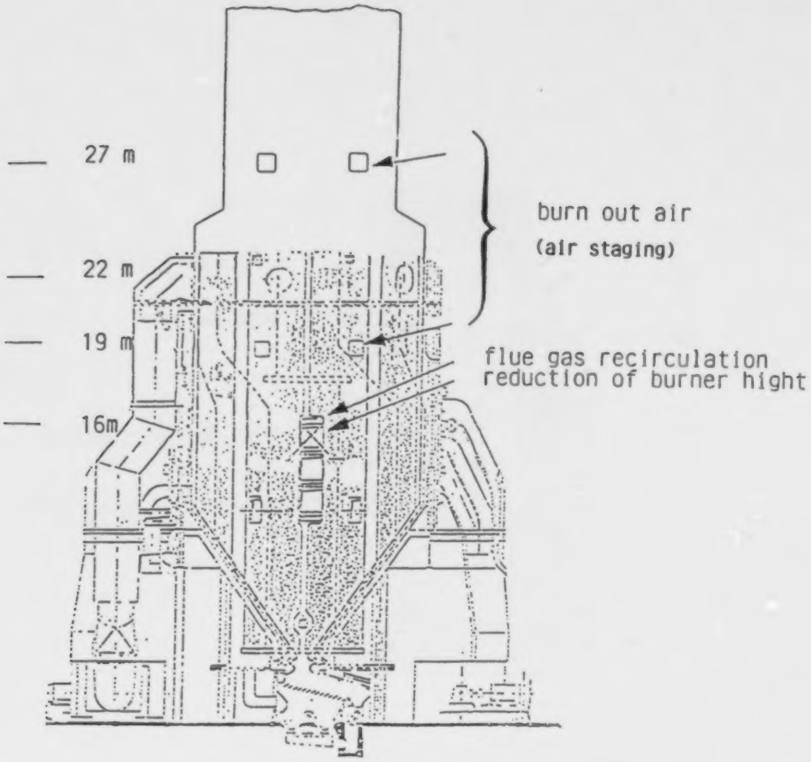
Fig. 8: The influence of flue gas recirculation



62 m
52 m
34 m
32 m
20 m
flue gas recirculation
burn out air
flue gas recirculation
reduction of burner hight

Fig. 9: NO_x-reduction by combined combustion modifications (600 MWe, example)

modifications:
- reduction of excess air
- air staging
- reduction of burner hight
- flue gas recirculation



27 m
22 m
19 m
16m
burn out air
(air staging)
flue gas recirculation
reduction of burner hight

Fig. 10: NO_x-reduction by combined combustion modifications (150 MWe, example)

modifications:
- reduction of excess air
- air staging
- reduction of burner hight
- flue gas recirculation

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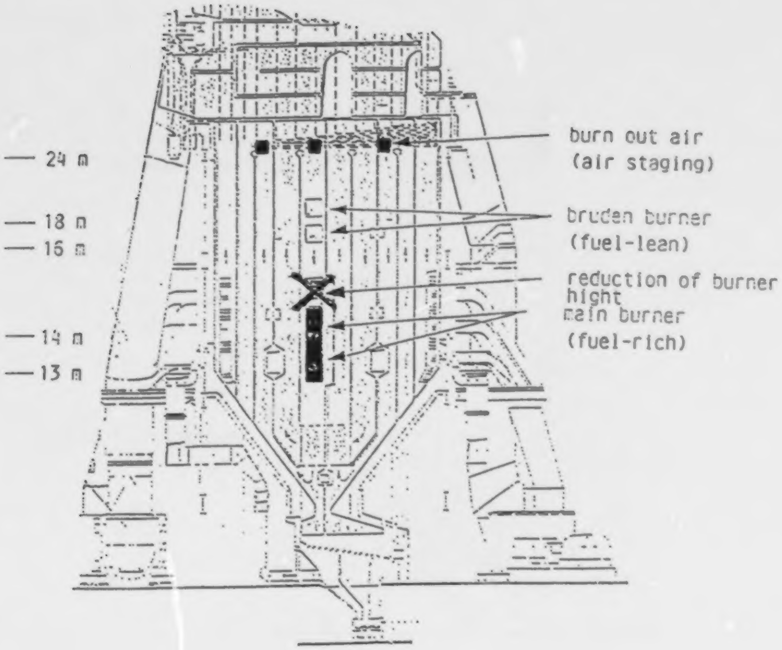

24 m
18 m
16 m
14 m
13 m
burn out air
(air staging)
bruden burner
(fuel-lean)
reduction of burner
hight
main burner
(fuel-rich)

Fig. 11: NO_x-reduction by combined
combustion modifications
(150 MWe, example)

modifications:
- reduction of excess air
- air staging
- reduction of burner hight
- bruden separation

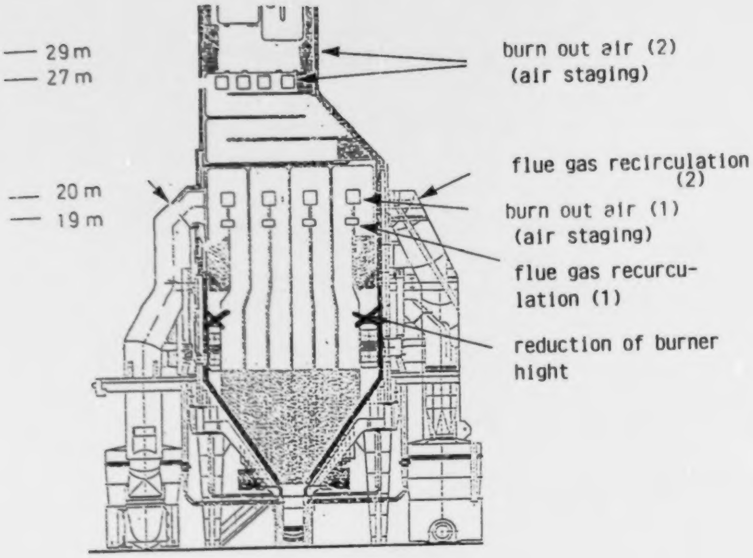
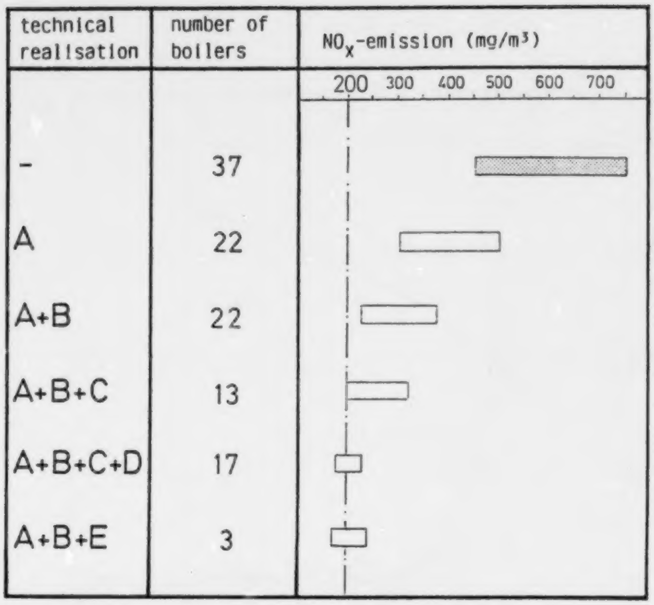

29 m
27 m
20 m
19 m
burn out air (2)
(air staging)
flue gas recirculation (2)
burn out air (1)
(air staging)
flue gas recurculation (1)
reduction of burner hight

Fig. 12: NO_x reduction by combined combustion modifications (75 MWe, example)

modifications:
- reduction of excess air
- air staging
- reduction of burner hight
- flue gas recirculation



A	excess air level reduction
B	air staging
C	burner hight reduction
D	flue gas recirculation
E	bruden separation

Fig. 13: NO$_x$-reduction by combustion modifications; results from selected boilers (150 - 600 MWe, brown coal)

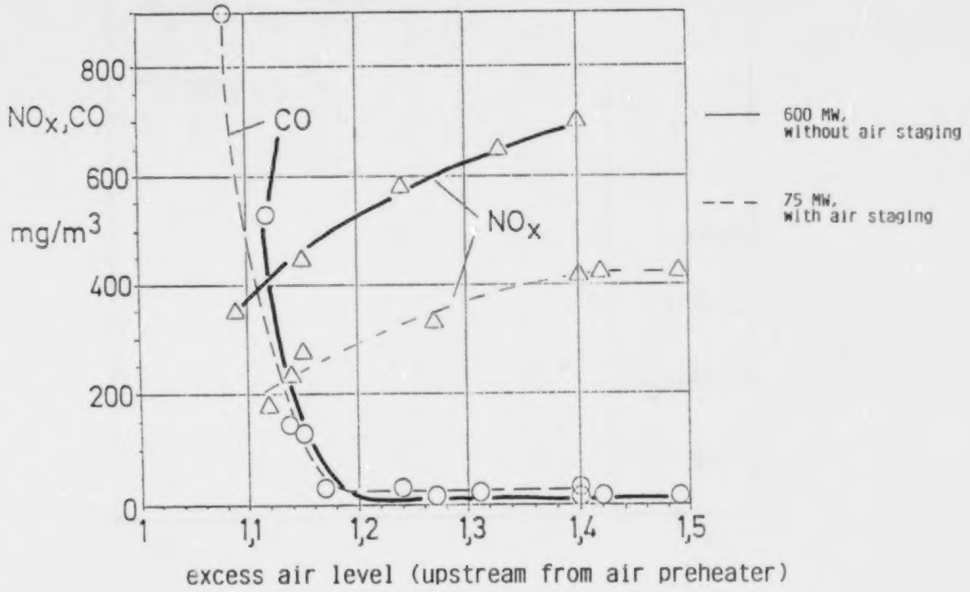


Fig. 14: NO$_x$- and CO-emission

PREDICING BOILER AND EMISSIONS PERFORMANCE BY COMPARATIVE TURBULENT/LOW NOx BURNER TESTING ON A LARGE TEST FACILITY

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ABSTRACT

Based on results from pilot- and full-scale testing, an 800 MW opposed-fired "cell-burner" boiler is being retrofitted with Foster Wheeler Controlled-Flow/Split-Flame (CF/SF) low NOx circular burners. The design conversion involves change-out of the burners, firing-walls, burner piping, and burner/pulverizer control system. Pilot-scale testing in an 80 million Btu/hr., two-burner facility showed no significant differences in combustion or unit thermal performance when firing with either turbulent or CF/SF low-NOx burners. Subsequent field testing indicated good agreement between measured and predicted boiler emission and thermal performance and provided a reliable basis to establish boiler performance guarantees. This paper discusses the design, cost, and schedule for the burner conversion and results from the pilot- and full-scale tests.

INTRODUCTION

In March, 1972 the State of New Mexico Environmental Improvement Board (EIB) promulgated Air Quality Control Regulation 603.B. This regulation set an emissions limit for nitrogen oxides of 0.70 pounds per million Btu from existing, pre-1971 coal-fired steam-electric generating units. All five of the coal-fired units at the Four Corners Station were determined to exceed this limit under normal full-load operating conditions.

The highest NOx emissions were produced by two Babcock & Wilcox (B&W), opposed-fired, supercritical, once-through boilers designated as Units 4 and 5. Each boiler is maximum continuous rated (MCR) for a steam flow of 5,446,000 lbs./hr. at 1000/1000 F and 3590 psig to produce a turbine-generator output of 820 MWG (780 MWnet). These boilers were built in the late-1960's and went into commercial operation in 1969 and 1970, respectively; i.e., 2-3 years before the State NOx regulation was established. B&W boilers of this period of manufacture were equipped with two- or three-nozzle "cell" burners specially designed to maximize combustion intensity and produce extremely high heat inputs in a compact burner zone. Figure 1 shows the three-nozzle cell burners on Units 4 & 5 illustrating the close vertical spacing of individual burner nozzles. As a result of this close spacing and rapid fuel-air mixing, the cell burners on Units 4 & 5 operate with flame temperatures approaching adiabatic conditions and produce an intense Burner Zone Liberation Rate (Q/BZS) of around 400,000 Btu/hr-sq. ft.(FWEC basis). Full-load NOx emissions average 1.25 pounds per million Btu at normal operating excess oxygen levels in the furnace.

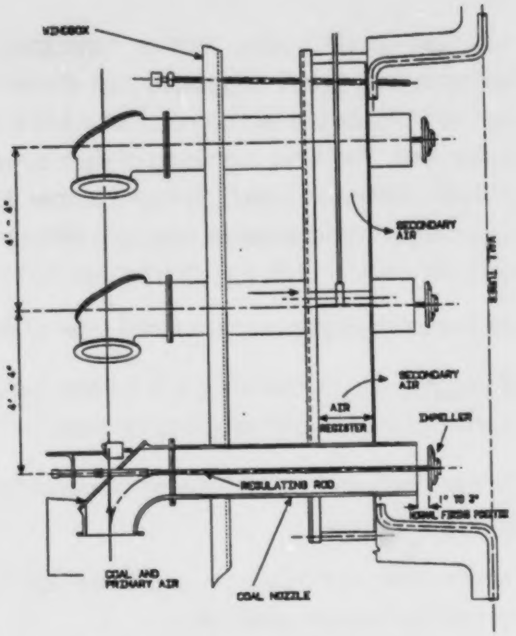


Figure 1 - Three Nozzle Cell Burner

Between 1973 to 1980, Arizona Public Service Company (APS), a joint owner and the operator of Units 4 and 5, conducted several NOx-control related test programs and attempted to achieve NOx compliance by operational methods. Initial NOx reduction efforts centered around staged combustion, off-stoichiometric firing. This technique involved shutting off the coal flow to selected burners or pulverizers while leaving the secondary air flow undisturbed. Although this approach reduced NOx emissions by 20 - 30 percent, it also aggravated already serious operational problems such as furnace slagging and bottom-ash clinkering, coal pulverizer overloading, coal pipe pluggage, and tube metal overheating in furnace outlet superheater and reheater sections. While some of these combustion problems were subsequently corrected or improved, further site testing in 1978 and 1980 showed that the 0.7 pounds per million Btu emission limit simply could not be met on Units 4 & 5 by burner out of service off-stoichiometric firing techniques. Based on these testing results and conclusions from technical studies conducted by KVB and the boiler manufacturer (B & W) advising against the application of overfire air ports or B&W low-NOx burners on Units 4 and 5, APS petitioned the EIB for operating variances from the 603.B regulation. The variances were requested on the basis that control technology was not available for reducing NOx emissions without jeopardizing unit operation. The EIB agreed and granted variances in 1980 and 1983. Pursuant to conditions of the variances, APS continued to investigate significant changes and developments in the area of NOx control technology. Ongoing developmental work by the EPA and EPRI during this time indicated that low-NOx burners (LNB) were the most attractive coal-fired retrofit option. Studies conducted in-house by APS in 1985 supported these conclusions and further suggested that shorter-flame design LNB may be compatible with the restricted furnace burner zone of Units 4 and 5 and capable of lowering NOx emissions to the regulation limit. The most promising of such burners was the Foster Wheeler Energy Corporation (FWEC) Controlled Flow/Split-Flame burner. However, several major concerns still remained regarding potential adverse operating effects and the design feasibility of replacing the cell burners with circular LNB. Specific process areas of concern were:

- lengthened flames impinging on the furnace side- or division- walls;
- increased slagging and/or clinkering in the lower furnace due to potentially closer proximity of the flame envelope to the walls;
- elevated furnace exit gas temperatures which could result if the LNB caused delayed combustion; and
- reduced combustion efficiency from potentially less intense, slower mixing flames and reduced oxygen availability.

To evaluate these issues APS elected to conduct a pilot-scale burner test program which was conducted at Foster Wheeler's Combustion & Environment Test Facility comparing the flame shape/length, emissions, and combustion performance of a high-turbulent burner (as presently installed on Units 4 & 5) to the FWEC low-NOx burner. Additionally, fuel-supply system engineering studies were completed to evaluate the performance, design and costs of alternate firing arrangements which would accommodate the new LNB design. This paper discusses the comparative burner tests, follow-up field boiler performance testing, and the preliminary design engineering effort ultimately leading to a decision to retrofit the Foster Wheeler LNB on Four Corners Units 3, 4 and 5.

PRELIMINARY SYSTEM DESIGN STUDIES

As noted in the Introduction, the three-nozzle cell burners on Units 4 and 5 posed a special design problem in that there was no commercial low-NOx equivalent. Two basic approaches were apparent: 1) develop and design a low-NOx, three-nozzle cell burner based on FWEC concepts which would fit into existing burner ports; or 2) widen the burner spacing to allow installation of a standard FWEC LNB design. Although FWEC expressed confidence in its ability to design a low-NOx "cell" burner, the high costs for performing exploratory developmental testing and the uncertain NOx and combustion performance of a full scale retrofit led APS and the other participant owners to pursue further firing arrangement studies. It was recognized that spreading the burners would substantially complicate the design and installation, and significantly increase costs; however, this conventional-design approach (versus an R&D path) offered the highest assurance of NOx compliance without compromising the performance, efficiency or reliability of the boilers.

OBJECTIVE AND REQUIREMENTS

OBJECTIVE

The objective of the preliminary system studies was to evaluate the performance, design, and costs of alternate firing arrangements for the Four Corners Unit 4 and 5 boilers which would provide a widened spacing between all burner openings. The existing boiler-plant design utilized nine pulverizers and eighteen, three-nozzle cell burners (i.e., 54 burner nozzles). Five pulverizers supply the front wall and four mills feed the rear wall. Each pulverizer supplies a pair of cell burners. The front and rear wall arrangement of existing burners is shown in Figure 2. A conventional arrangement for FWEC low-NOx circular burners of the capacity needed on Units 4 and 5 required vertical and horizontal spacings between burner openings of at least 8 feet.

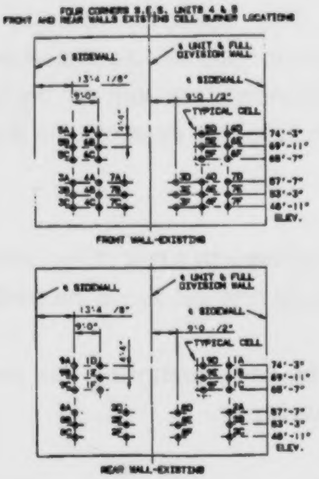

FOUR CORNERS S.E.S. UNITS 4 & 5
FRONT AND REAR WALLS EXISTING CELL BURNER LOCATIONS
SIDEWALL
UNIT & FULL DIVISION WALL
SIDEWALL
13'4 1/8"
9'0"
9'0 1/2"
4'4"
TYPICAL CELL
74'-3"
69'-11"
65'-7"
57'-7"
53'-3"
48'-11"
ELEV.
FRONT WALL-EXISTING
REAR WALL-EXISTING

Figure 2

REQUIREMENTS

The following requirements were established for any acceptable firing arrangement design:

(1) The firing pattern be of a conventional design and "successfully demonstrated" (with respect to NOx and combustion performance) on a large coal-fired utility boiler.

(2) Localized heat fluxes in the burning zone should not exceed those produced by the cell burner array.

(3) Furnace exit gas temperature must not increase more than 50 F above that of the cell burner.

(4) Boiler slagging and bottom-ash clinkering problems must not be aggravated.

(5) The pulverizer system and Unit equivalent operating availability cannot be significantly reduced.

FIRING ARRANGEMENT ALTERNATIVES

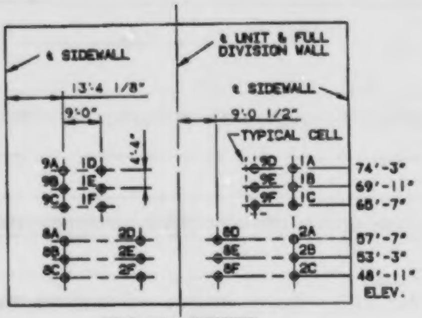
Initially five (5) different firing arrangements were identified and assessed for performance and general design practicability. This "screening" revealed that two of the options either had numerous major interferences with boiler structural steel and piping or resulted in unequal firing rates among burners and imbalanced heat input into the two combustion chambers formed by the full-height division wall. The following three options showed promise and were selected for further detailed evaluation:

1) Nine pulverizers and 54 burners with a row of six burners relocated on the front firing wall to an elevation approximately nine feet above the existing top row.

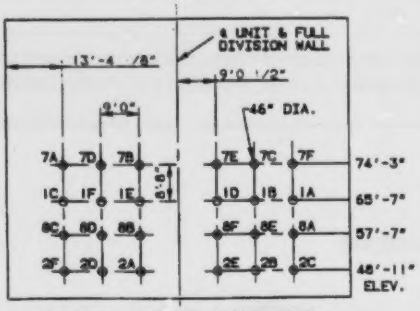
2) Eight pulverizers and 48 burners, arranged in four rows of six burners on each firing wall, utilizing B&W MPS-89N pulverizers.

3) Eight pulverizers and 48 burners, configured as under Option (2) but utilizing capacity-upgraded B&W MPS-89G series pulverizers.

A readily-apparent means of widening the burner spacing on most of the cells was to take center burner nozzles and relocate them horizontally within the existing firing zone. Although this worked well for the rear wall, as illustrated in Figure 3, the greater number of burners (30 versus 24) in the front wall necessitated that a group of six burners be moved upward. This was the concept of Option (1). Burner openings at elevation 53'-3" would be relocated to elevation 82'-11" as illustrated in Figure 4. The widened burner spacing and lowered burner zone heat release rate

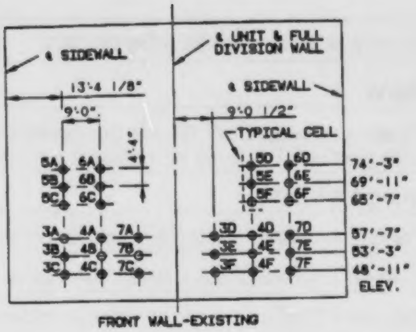

℄ SIDEWALL
℄ UNIT & FULL DIVISION WALL
℄ SIDEWALL
13'-4 1/8"
9'-0"
9'-0 1/2"
TYPICAL CELL
4'-4"
74'-3"
69'-11"
65'-7"
57'-7"
53'-3"
48'-11"
ELEV.

REAR WALL-EXISTING

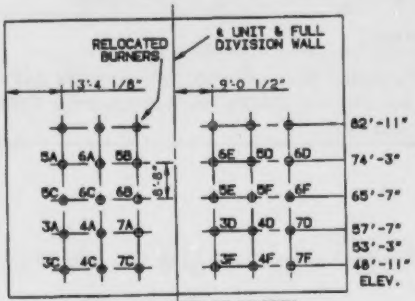

℄ UNIT & FULL DIVISION WALL
13'-4 1/8"
9'-0 1/2"
9'-0"
46" DIA.
8'-0"
74'-3"
65'-7"
57'-7"
48'-11"
ELEV.

REAR WALL-RELOCATED BURNER PORTS

Figure 3


℄ SIDEWALL
℄ UNIT & FULL DIVISION WALL
℄ SIDEWALL
13'-4 1/8"
9'-0"
9'-0 1/2"
TYPICAL CELL
4'-4"
74'-3"
69'-11"
65'-7"
57'-7"
53'-3"
48'-11"
ELEV.

FRONT WALL-EXISTING


RELOCATED BURNERS
℄ UNIT & FULL DIVISION WALL
13'-4 1/8"
9'-0 1/2"
8'-0"
82'-11"
74'-3"
65'-7"
57'-7"
53'-3"
48'-11"
ELEV.

ARRANGEMENT AFTER RELOCATION OF BURNERS AT 53'-3" TO 82'-11"

Figure 4

for this firing pattern offered the optimum NOx reduction while retaining all nine mills. However, major concerns with this concept were: 1) increased furnace exit gas temperature and 2) substantial steel and piping interferences in the upper windbox with the relocated row of burners.

Options (2) and (3) eliminated the need to raise burners vertically on the furnace front wall by simply eliminating one pulverizer and six burners from the design. The reason this concept appeared feasible, in general, was that Units 4 and 5 were in the middle of being retrofit with new, increased capacity B&W MPS-89N pulverizers. B&W quoted the new pulverizers with a nominal capacity 20 percent above the original CR-77 mills; (i.e., 60 tons per hour versus 50 tons per hour). Thus it appeared that eight MPS-89N mills would provide an acceptable boiler plant design on the basis that full-load MCR steam output from Units 4 & 5 could be carried with one pulverizer out of service. Furthermore, industry experience with the MPS-89N series pulverizers had shown them to be very reliable. Going to Option (3) effectively restored the lost capacity of converting from nine to eight pulverizers; however these mills required substantially larger top housings. To evaluate the three options further, APS contracted with :

CONTRACTOR & WORK PERFORMED
B&W
To assess changes in FEGT with the elevated row of front wall burners; and to evaluate the capacity of the MPS-89N mills (and new P.A. fans) with different fuel characteristics.
BLACK & VEATCH
Performed detailed availability analyses on the entire fuel-supply system with various firing arrangements.
UNITED ENGINEERS & CONSTRUCTORS
Evaluated interference and clearance problems with the enlarged G-series pulverizers and reviewed the scope of required burner piping modifications.
FWEC
Evaluated NOx reduction effectiveness and made a detailed assessment of physical interference problems for the elevated row of front wall burners under Option 1; evaluated Option 2 configururation and performed detailed test program.

The following discusses the results of those evaluations.

COMPARATIVE BURNER TESTS

TEST FACILITY DESCRIPTION

Comparative burner testing was performed on Foster Wheeler's Combustion and Environmental Test Facility. Shown in Figure 5 the CETF is configured to simulate a commercial steam generator. The conditions produced include:

- Furnace residence time is limited to about 2 sec. maximum between the burner pattern centerline and the furnace exit.
- Furnace Exit Gas Temperature (FEGT) is about 2200F max. and can be varied by adjusting total furnace absorption.
- Burner/furnace aerodynamics are similar to those of commercial equipment as are furnace mixing patterns, due to both overall geometry and the two-burner-high arrangement.
- The arch configuration, which is required to provide proper conditions for low volatile fuel combustion is also important to produce the desired velocities/residence times and FEGT. The reduced upper furnace cross-section is responsible for the increased velocity and resultant decreased residence time. Decreased upper furnace heat transfer surface, as compared to the same unit

without the arch, reduces absorption above the burner zone, thereby increasing FEGT to levels normally achieved in commercial equipment. Commercial practices, used throughout the CETF system design have been mated with research-oriented considerations wherever practicable to maximize the usefulness and flexibility of the system.

A direct firing system is utilized; consisting of a hot-primary air-swept ball mill supplying two 40 million Btu/hr burners. Commercial (Forney) gas ignitors, ignitor and main flame scanners, as well as burner management and overall control system are employed.

Combustion gases flow upwards from the burners, over the nose and down through an economizer, followed by a heat-pipe air heater and then to the stack. The furnace is a refractory-covered water jacket operating with natural circulation and feeding a steam drum.

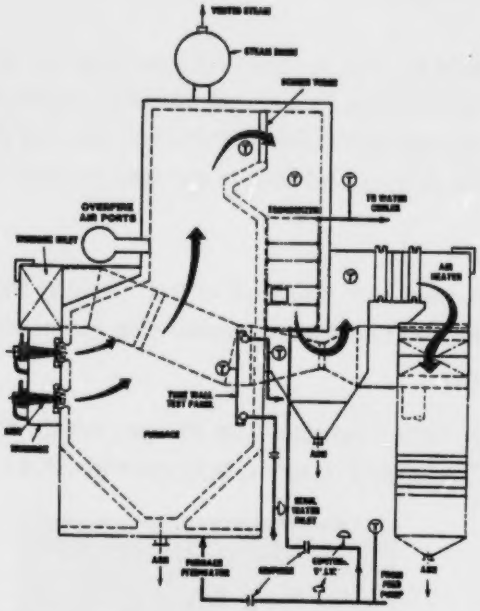


Figure 5 - CETF Heat Transfer Surface Arrangement

Independent water circuits supply the furnace, economizer and tube-wall test panel located on the rear wall. Calorimetric measurements are made of each circuit in order to obtain absorption duties.

TEST PROGRAM OVERVIEW

The primary purpose of the comparative burner testing was to quantify any potential changes in FEGT or heat transfer duties when substituting Foster Wheeler's Controlled Flow/Split-Flame low NOx burner for the turbulent intervane burner. The latter was installed as original equipment on Four Corner's No., 3 a 225 MW FW steam generator, and has flame characteristics nearly identical to the high turbulent closely-spaced cell burners on Units 4 and 5.

Of secondary interest, although still significant, interest were changes in emissions and other combustion conditions. This was the case because the CF/SF low NOx burner has been first in service since 1979; having been retrofitted to Public Service New Mexico's 360 MW San Juan #1. On that unit NOx was reduced about 55%, to below 0.45 lb/million Btu, with no changes in boiler performance. Similarly, other retrofits and new unit applications yielded low NOx emissions with normal boiler performance.

Nevertheless, APS elected to fund an intensive test program to obtain data specific to the conditions at Units 3, 4 and 5 at the Four Corners Station; utilizing the same coal fired on those boilers. These results, coupled with boiler performance data obtained on Units 3 and 5, would enable Foster Wheeler to provide definitive guarantees for both emissions and boiler performance.

A two segment test program was prepared to first, develop baseline data for the turbulent intervane burner; and second to obtain equivalent data for the low NOx burner. The following comparisons were made:

- Changes in flame characteristics (shape, length, flame temperature axial gradient). These were observed both visually with a Land heat flux probe.

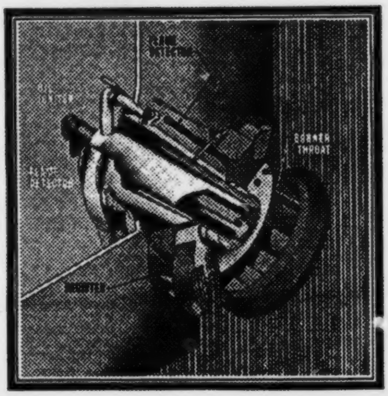


Figure 6 - Intervane Burner

- Ability to match the CF/SF low NOx burner's flame characteristics (FEGT, horizontal and vertical heat flux profiles) to those of the intervane burner while achieving NOx reductions of at least 50% without decreasing carbon burn-out efficiency.
- Changes in FEGT, or distributions of heat flux on the furnace walls caused by possible differences in flame characteristics or slagging conditions.
- NOx reduction effectiveness of the CF/SF burner.
- Changes in combustion efficiency (CO and carbon burn-out efficiency).

A statistically-based test matrix was developed for each burner's test series. A total of 25 intervane and 27 CF/SF burner tests were performed at full load to permit statistically significant results to be obtained. Formal test data, for the statistical analysis comparisons were taken after each burner's combustion and emissions performance was optimized and its flame shape adjusted for compatibility with the furnace confinement.

BURNER DESIGNS TESTED

The FW Intervane Burner, shown in Figure 6, has been in use for many years on coal-fired boilers. It produces a short, bushy flame with good combustion efficiency (low CO and unburned carbon), but generates high NOx levels. A single air register is used to produce high secondary air swirl which results in a strong recirculation zone in the flame. Coal and primary air are injected into the furnace through an annular coal nozzle. The resultant rapid mixing between the fuel and combustion air produces the combustion characteristics noted above.

Flame characteristics have a significant role in the design of a steam generator since they define the furnace heat absorption profile. A short, intense flame will produce a high absorption rate in the burner zone, yielding an FEGT commensurate with that absorption profile.

A burner which produces a long flame will generate a flatter absorption profile with, generally, a higher FEGT. Since most boilers are designed for short, intense flame burners, such as the intervane burner used on Four Corners #3 or the cell burner used on Four Corners #4/5, retrofitting such a unit with a long flame burner could have severe operational and performance consequences. Among these are:

- High FEGT, due to reduced furnace absorption, resulting in higher stack temperatures; thereby reducing tube life and overall boiler efficiency.

- Increased fouling of superheater and/or reheater surfaces; causing decreased heat transfer surface duties; again resulting in reduced efficiency.
- Flame impingement on the rear wall of front-wall fired units; causing slagging, tube overheating and, potentially, tube failures.
- Overheating of superheater and reheater tubes causing reduced service life.
- Increased carbon carryover.

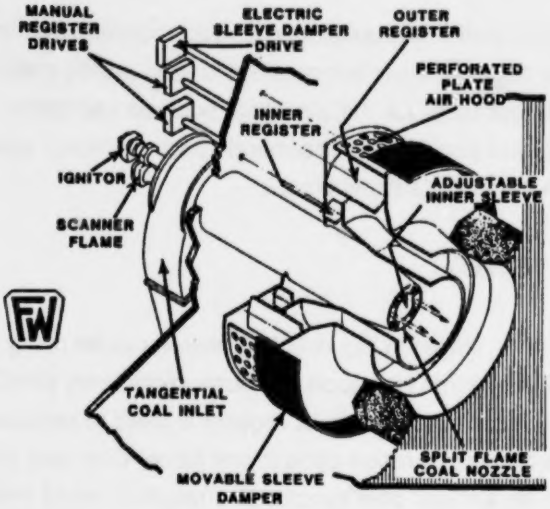

MANUAL REGISTER DRIVES
ELECTRIC SLEEVE DAMPER DRIVE
OUTER REGISTER
PERFORATED PLATE AIR HOOD
INNER REGISTER
IGNITOR
ADJUSTABLE INNER SLEEVE
SCANNER FLAME
FW
TANGENTIAL COAL INLET
SPLIT FLAME COAL NOZZLE
MOVABLE SLEEVE DAMPER

Figure 7 - Controlled Flow/Split Flame Burner

Consequently, in order to be compatible with the pre-NSPS furnace designs of Units 3, 4 and 5, an LNB must be capable of producing a flame envelope and absorption pattern similar to that of original equipment turbulent burners.

The FW Controlled Flow/Split-Flame low NOx burner, shown in Figure 7, was developed in the mid-1970's. During the CF/SF burner's developmental phase the following design philosophy was adhered to:

- Flame length and envelope to be equivalent to that of the turbulent burner designs that have been in historical use.

- Thermal characteristics to be such as not to compromise boiler design criteria; the burner could then be utilized in new boilers without modifying the boiler design from that used with turbulent burners and in retrofit cases without adversely impacting boiler performance.
- Combustion air flow and swirl to each burner to be independently controllable.
- Adjustable primary air/coal velocity to ensure optimum relation between primary and secondary air steams.
- No increase in primary or secondary air pressure drop so that existing PA and FD fans can be used.
- Burner capacity of cover the complete range of industrial and utility use: approximately 30 to 300 million Btu/hr.
- Plug-in retrofitability, i.e. no pressure part changes, no burner piping rearrangement and no major windbox modifications when installed on existing FW boilers.

The successful implementation of this philosophy has yielded good combustion efficiency, with NOx reductions of 50-60%, excellent stability and no detrimental affects on boiler efficiency or operation.

The burner's components are described below:

- Perforated Plate with Sleeve Damper: used to control secondary air flow on a per burner basis. By measuring the pressure drop across the perforated plate an index of air flow is obtained. The air distribution vertically and horizontally within the windbox is thus optimized by adjusting the sleeve dampers to obtain equal burner stoichiometries. This is a one-time optimization after which the "open" position is fixed. The sleeve damper has "closed", "ignite" and "open" positions and is used, instead of the main radial vane register, to shut off the air flow when the burner is out of service. It is controlled by an electrically operated linear drive, but is not modulated with load.
- Dual Series Registers: provide improved flame shape control and NOx reduction by two-staging the secondary air. A key mechanical reliability feature of this register configuration is that the blades and drive mechanisms are set back from the furnace wall and are well "shaded" from direct flame radiation. Consequently, the registers operate at windbox temperature and do not overheat, warp or bind. Additionally, once the flame is optimized for proper

flame shape and low NOx, the registers are fixed. They remain in their optimum position and are not modulated with load or closed when the burner is taken out of service since the sleeve damper performs that function. The burner essentially becomes a fixed register type with the option for adjusting the register if a major fuel change occurs, the drive mechanisms being manual.

- Adjustable Coal Nozzle: allows primary air/coal velocity to be optimized without changing primary air flow. The proper relationship between primary and secondary air is important for both NOx control and good combustion. Once optimized no further adjustment is required.
- Split Flame Nozzle: segregates the coal into four concentrated streams. The result is that the volatiles in the coal are driven out and are burned under more reducing (oxygen-starved) conditions than otherwise would occur without the split flame nozzle. The volatiles in the coal contain a high percentage of fuel bound nitrogen. Combustion under reducing conditions converts these volatile nitrogen species into N_2, substantially reducing NOx formation.

Succinctly, only the sleeve damper, used to shut off the secondary air flow, is moved when the burners are taken in or out of service. Thus after optimization the burners become fixed register types.

Coal for the APS test program was provided by Arizona Public Service from the Navajo Mine located adjacent to the Four Corners Station; approximately 800 tons of coal was utilized during the testing. The following section presents the results of the test program.

SUMMARY OF COMPARATIVE BURNER TEST RESULTS

The intent of data collection and analysis was to make comparisons at specific load and excess 0_2 conditions and to repeat tests several times to determine the amount of variability in the dependent variables due to independent variables changing in the system. A difference of means t-test was the preferred test; however, during actual testing it was not possible to control the independent varaibles (e.g. load, 0_2) as closely as desired. Furthermore, changes in furnace cleanliness with time over the first two weeks of testing (due heat transfer surface seasoning from the 22 percent ash coal) introduced further unanticipated variability in the data. Hence, the intervane and low NOx burner data sets turned out to be widely scattered over the specified load and 0_2 test range.particularly in FEGT and furnace and convection pass absorption rates. As a result, the "sample" variances were large. This problem was addressed by applying techniques of multiple regression analysis to correlate the response variable to statistically significant independent variables. This procedure subdivides the total variability in the dependent variable data into variations explained by a postulated model and unexplained variability. The net result was a reduction in unexplained variability, and consequently, a reduction in the uncertainty interval for the response.

The evaluation and statistical analyses of the test data were jointly performed by APS and FWEC personnel. The following summarizes the results:

Combustion and Thermal Characteristics:
Of particular interest is the potentially adverse effects of lengthened flames causing rear wall slagging and increased convection pass temperatures on Units 3, 4 and 5. The differences in flame characteristics between the two burner types were evaluated on the CETF by both analytical and visual methods. The following summarizes the results both analytical and visual methods.

Rear Wall Flame Impingement:
The high-turbulent IV burner produces luminous flames which are short and bushy; flames were well off the rear wall of the CETF furnace which has a depth of 16 feet, during the APS testing -- approximately 3-4' for the upper burner and 5-6' for the lower burner. The low NOx CF/SF burner is a more flexible device due to the dual registers and adjustable coal injector which permit a wide range of flame shapes to be developed. However, under optimum conditions selected for the APS comparative testing, low NOx flames had the same shape/length as the IV burner flames but with improved stability.

Rear Wall Slagging:
A specially designed tube wall panel was installed on the back wall of the furnace to determine if any adverse changes in rear wall slagging were caused by the low NOx burner. The slag panel was designed to produce a tube metal surface temperature equivalent to that of Unit 3. Numerous observations revealed no change in rear wall slagging and in fact the slag panel's heat absorption was lower with the CF/SF burner as compared to the IV burner. In general, gas temperatures near the rear wall were 200F lower with the CF/SF burners as compared to the IV burners. Based on these two observations no increase in rear wall slagging on Four Corners Unit #3 is expected. Furthermore, qualitative observations of furnace refractory wall slag build-up indicated reduced deposition during the CF/SF burner operation.

Convection Pass Temperature:
The temperature of most importance in boiler design/operation is the Furnace Exit Gas Temperature (FEGT), which is the thermal fulcrum of the steam generator or boiler. It defines the furnace conditions and performance capabilities of the convection pass by setting the heat head available

for the superheater, reheater, economizer and air heater.Increased FEGT will result in reduced steam generator efficiency by increasing spray de-superheating requirements and raising stack gas temperature. If the FEGT increases beyond safe design limits, the superheater tube metal temperatures can rise high enough to cause structural damage, and excessive ash build-up may occur within the closely-spaced superheater tubing. Consequently, it is critically important that any combustion modifications for NOx emission control purposes not raise FEGT beyond its design range.

Two methods of evaluating any changes in FEGT were utilized during the APS testing program:

- Direct measurement using a multiple-shielded, high-velocity thermocouple (MHVT). This method was marginally successful due to problems of ash pluggage in the ceramic shields.

- Back calculation of FEGT from the air heater inlet gas temperature (convection pass outlet) through the convection pass.

The back-calculation method, which is a standard technique used for commercial steam generating equipment, utilizes the flue gas temperature as measured with thermocouples at the boiler's gas exit (usually the economizer exit). Heat balance calculations are then used across each of the intervening heat transfer banks until the FEGT is determined.

In the case of the CETF boiler, the only bank upstream of the exit is the gas cooler (essentially a low pressure economizer). Since, by measurement, the unit load and excess air (and therefore gas flow), gas cooler outlet temperature and gas cooler duty were known, we can then calculate the gas cooler inlet temperature (Tgci). This is the critical temperature from which the FEGT must be determined via back-calculation through the convection pass upper cavity and screen tubes.

The method used to determine convection pass differences due to burner type was as follows:

Calculate Tgci for each test and determine, statistically, the significance of any differences between turbulent and low NOx burners. From the mean values of the respective Tgci's, calculate the predicted mean value of each FEGT.

The statistical decision criteria, defined by APS, required acceptance of a null hypothesis that there was no significant difference between the furnace-outlet gas temperatures produced by each burner. The required statistical test performed on the mean Tgci at 75 million Btu/hr heat input and 3.5% O_2 dry revealed:

	Tgci (IV)		Tgci (CF/SF)
Mean	1727°F		1731°F
No. of Data	25		27
Pooled Variance, Sp		30°F	
Degrees of Freedom		45	
Student's ^{t} (from samples)		0.133	
$t_{0.05,v}$ (critical value)		1.68	

Therefore, since $t_{sample} < t_{0.05}$, the null hypothesis that the means of the two data sets came from the same population (there is no difference in Tgci due to burners), is accepted.

Further, since FEGT is directly dependent, data point by data point, on Tgci there is no difference between FEGT's between the burners.

The calculated FEGT's for the respective mean Tgci's were:

Burner Type	Tgci	FEGT
IV	1727	2139
CF/SF	1731	2148

The resultant difference in FEGT's (0.42%) is too small to have any functional effect on the Four Corners units, if in fact there is a real difference of this magnitude.

EMISSION DATA:

- NOx:

  The mean NOx emission rate at full load (80 million Btu/hr) and 20% excess air (3.5% O_2 dry) with the IV burner was 1.00 lb/million Btu.

  The mean NOx emission rate from the CF/SF low NOx burner under the same conditions was 0.41 lb/million Btu. Thus, the average NOx reduction produced by the CF/SF burner was 59%.

- CO:

  Under conditions representative of normal coal-fired utility boiler operation (i.e., above 3.0% excess O_2, dry), CO levels were statistically equivalent for both the IV and CF/SF burners: 20-25ppm.

- Unburned Carbon:

  This parameter was calculated as percent efficiency loss, rather than percent unburned carbon in the ash, since efficiency loss reflects the actual effect on steam generator performance. UBC was one of the decision parameters defined by APS for evaluation.The CETF test data show:

UBC for IV burner	=	0.256%
UBC for CF/SF burner	=	0.322
Increase	=	0.066%

The increase amounts to 25% over the baseline IV tests. It should also be noted that both values are in the range of normal coal-fired utility boiler operation and of current combustion efficiency conditions at Four Corners #3. Also, during the testing no effort was made to reduce unburned carbon levels from the LNB to match those of the turbulent burner.

In summary, it was clearly demonstrated the CF/SF low NOx burner can reduce NOx nearly 60% while maintaining a short flame, commercial quality combustion efficiency and no significant change in furnace thermal characteristics (particularly FEGT) or boiler efficiency.

BOILER PERFORMANCE EVALUATIONS

APS requested FWEC to provide both emissions and boiler performance guarantees for Units 4 and 5 if they are converted to CF/SF low NOx burners. A reliable set of operating data was needed to provide the basis upon which predictions, and subsequent guarantees could be made. The methodology Foster Wheeler uses to evaluate emissions and performance capability of a unit to be retrofited with low NOx burners is to compare measured values (NOx, CO. FEGT, etc) with respective predictions from FW's proprietary calculational techniques. For this case comparisons were made between the cell-burner equipped unit and that unit as if it were equipped with intervane and then low NOx burners. In particular:

- Compare cell-burner NOx emissions with predicted emissions from the boiler if it were equipped with the intervane burner.

- Predict NOx emissions from the unit if it were retrofitted with CF/SF low NOx burners.
- Compare measured boiler performance with predictions for both IV and CF/SF burners as evaluated by FW's boiler performance computer program.

Since the CF/SF burner produces a flame shape that is not significantly different from that of turbulent high NOx burners, and there is no evidence from several industrial and utility boiler retrofits that the FEGT is increased, FWEC's boiler performance program does not differentiate between the intervane and low NOx burners. The pilot scale test program, outlined above, confirms the previous experience demonstrating that there is no significant difference in FEGT between the intervane and CF/SF burners, although the latter reduces NOx by nearly 60%.

FWEC was contracted to do a complete boiler performance test on Four Comers #5 in order to develop the necessary thermal and emissions data to enable guarantees to be offered. Table 1 summarizes key data from the as-found unit and compares it to predicted performance. Performance is predicted for the unit with the existing configuration and with the new 8-mill/48-burner configuration.

Results indicate that boiler performance would not be significantly changed by retrofitting the CF/SF low NOx burners in the new configuration.

TABLE 1: BOILER PERFORMANCE DATA MEASURED VS PREDICTED

Unit Configuration	**Existing**	**Exisitng**	**New**
No Mills I/S	9	9	8
Excess Air	18	18	18
FEGT	2394	2404	2405
RH Spray (1000 lb/hr)	0	5.4	5.7
RH Temp	1029	1000	1000
NOx (lb/10^6 Btu)	1.27	1.32	<0.6

PERFORMANCE EVALUATIONS

NOx Reduction Effectiveness

Foster Wheeler predicted that if the cell burners were all replaced with the CF/SF low-NOx burner in a conventional widened burner firing pattern NOx emissions of Units 4 & 5 could be reduced by 50 to 55 percent; or to an emission level at full-load of between 0.55 - 0.60 pounds per million Btu.

Independent estimates of the NOx performance achievable with a full retrofit of low-NOx design burners in the cell array was in the range of 0.85 - 0.90 lbs/million Btu. The reduced effectiveness predicted for this approach was based on concerns over flow and temperature interferences between closely-spaced adjacent flame envelopes such that proper staging could not be achieved. However, Foster Wheeler's opinion is that a low NOx cell design based on CF/SF Technology would provide lower NOx levels than these predicted by the independent estimates.

Pulverizer and P.A. Fan Capacity:

B&W analyzed pulverizer and primary-air fan performance on the basis of coal properties shown in Table 2. Results from the analysis confirmed that MCR boiler output could be achieved when operating with seven MPS-89N mills, in their "worn" condition at 70% fineness, and firing the Design (worse-case) coal. At this condition the pulverizers would be operating at their full rated capacity. However, Units 4 and 5 are normally operated at a derated, full-load output of 743 MWnet. This corresponds to approximately 95% of boiler MCR capacity. Additionally, less than five percent of the time is a coal received with a heating value below 8500 Btu/lb. B&W's analysis showed that during normal full-coal operation with eight pulverizers in service the mills would be loaded to approximately 80 percent of rated capacity.

TABLE 2

COMPOSITION, WT. %		
PARAMETER	**DESIGN COAL**	**AVERAGE COAL**
Ash Content	23.0	22.0
Moisture	16.01	13.0
Fixed Carbon	31.0	34.5
Volatiles	31.0	30.5
Nitrogen	1.2	1.1
Heating Value, Btu/lb	8500	8750
Grindability, HGI	43	50

B&W also evaluated the capability of new TLT-Babcock primary air fans to supply the necessary quantity of hot, primary-air against the increased resistance of an eight mill system configuration. Based on one mill out of service operation and firing the "Design" coal, B&W calculated that the new fans had margins of 20 percent on flow and 29 percent on pressure.

Effect on Furnace Exit Gas Temperature

Both Foster Wheeler and Babcock & Wilcox were asked to evaluate expected increases in furnace exit gas temperature (FEGT) for a retrofit of their LNB in the 48 burner widened firing pattern (Options 2 or 3) and with a relocation of six burners in the lower front firing wall to an elevation nine feet above the existing top row (Option 1). The following results were calculated from each manufacturer's Furnace Performance program:

	Predicted Increase FEGT (F)	
	48 Burner Array	54 Burners with an Elevated Row on Front Wall
B & W	12.0	20.0
FWEC	0.0	10.0

B&W noted that the slower combustion and "lazy" flames of its LNB accounted for the predicted 12 degrees F increase in FEGT with the widened 48 burner firing pattern. The Foster Wheeler prediction for Options 2 or 3, based on FW's other field data, was subsequently supported by the CETF pitot-scale testing.

Design FEGT at MCR conditions on Units 4 & 5 is around 2250F MHVT. General design practice on high ash content coals and those with high slagging potential is to limit the FEGT to the Initial Deformation Temperature (oxidizing) of the ash. A minimum value for $T_{I.D.O.}$ for Four Corners coal is 2300F. Hence the approximate 10F increase in FEGT calculated by both manufacturer's from elevating a row of front wall burners was judged acceptable.

Changes in Localized Heat Fluxes

For either the 8 or 9 mill widened burner firing patterns, it was expected that localized heat inputs into the surrounding burner-zone waterwalls would change from those produced by the cell burners.The general feeling was that the widened pattern of LNB would provide a more even distribution of heat release. Detailed analysis confirmed this belief. Figure 8 shows the distribution of incident radiative fluxes predicted on the division wall from "slices" of the flame envelopes (near the point of peak thermal emission rate) for the cell and "spread out" burner patterns. As anticipated, directly opposite the concentrated heat release of the lower cell burner closest to the division wall, the localized heat fluxes were significantly higher than those produced by the widened burner spacing.

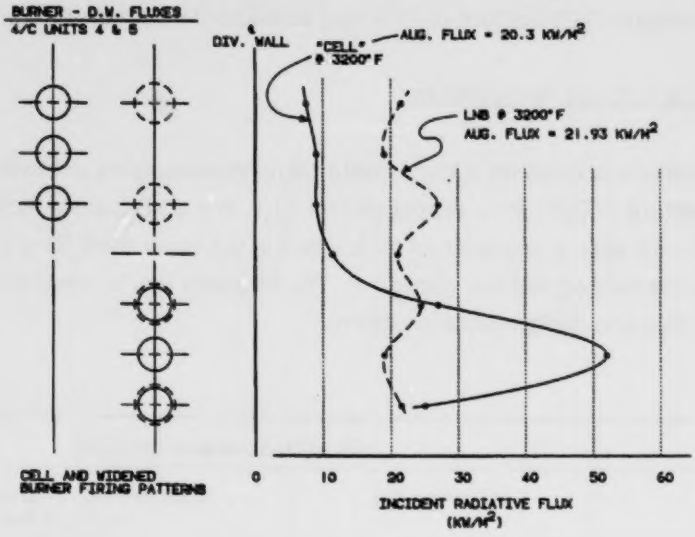


Figure 8-Incident Radiative Flux Cell vs. Low NOx Burners

It should be pointed out that this analysis was only intended to be indicative of the changes to be expected from the revised burner pattern and was not formulated to accurately account for the total incident radiative flux on the wall surface. Peak total incident fluxes on the order of 500 KW/meter sq. (or around 160,000 Btu/hr - ft.sq.) would be expected in the highly confined burner zone of Units 4 & 5.

Availability Losses with Removal of One Pulverizer

Black and Veatch Consulting Engineers (B & V) developed a sophisticated computer model, using Monte Carlo simulation techniques, to analyze comparative pulverizer-system and unit availabilities with installation of 8 or 9 MPS-89 pulverizers. The model incorporated the physical arrangement and operating logic of the entire Units 4 & 5 fuel supply system. The analysis required estimates of the mean-time-between-failure (MTBF) and the mean-time-to-repair (MTTR) for all of the fuel system components; this data was developed by APS based on plant operating and maintenance records.

The model accounted for variability of coal properties, unit heat rate, and the availability of first-point heaters and the balance of plant by use of statistical probability distributions. Other features of the model included realistic accounting for unit minor and major overhauls, preventative maintenance on the pulverizers, and storage capabilities of the coal silos. The base case modelled nine MPS-89 N pulverizers on each unit, and compared its availability performance to modified systems using eight MPS-89 N or G series mills. The results in terms of average equivalent operating availabilities (EOA-%) are summarized below:

Subsystem	Nine MPS-89 N Pulverizers	Eight MPS-89N Pulverizers	Eight MPS-89G Pulverizers
Pulverizers	99.83	99.09	99.58
BOP	76.22	76.22	76.22
Overall	76.15	75.82	76.04

Thus the effect of removing one pulverizer was an average decrease in unit EOA of 0.33 percent, or an overall mean difference in energy production of 20,000 MWH. At APS' current and projected costs for replacement power, the 20,000 MWH loss of energy production corresponded to a differential annual fuel cost penalty of approximately $150,000. Two-thirds of this loss could be recaptured by upsizing to MPS-89G pulverizers.

Sensitivity analyses were performed for the 8 mill, MPS-89N system design to assess the effect of improved component reliability. Base MTBF values were doubled (i.e., failure rates were cut in half) for each component. Results of the analysis showed that unit EOA was fairly insensitive to component reliability within the estimated range of component failure rates. For example, reducing coal feeder failures from 48 to 24 per year/unit only increased unit EOA by 0.03%. The most sensitive operational problem in the analysis was coal silo plugging which stops the coal flow to two pulverizers for an average of 20 hours. Silo plugging accounted for over 50 percent (11,000 MWH) of the total lost generation.

DESIGN REVIEWS

Interference Problems with Elevated Row of Front Wall Burners - The lower furnace of Units 4 & 5 is a two-pass design where fluid enters alternating tubes around the periphery in the first pass and flows upward to an intermediate elevation where it is collected and rerouted back down to the bottom of the furnace. The second pass outlet flows are collected at the same elevation as the first pass outlet and routed through "mix bottles" for pressure and temperature equalization before being introduced in a third pass to the top of the furnace. This enclosure mix area on Units 4 & 5 is approximately 10 - 15 feet above the existing top elevation of cell burners, on both the front and rear walls. APS Engineering suspected that numerous interferences would occur in trying to relocate a row of burners in this area.

Detailed review by APS and FWEC revealed the following major burner interferences in the mix enclosure area:

1. The first pass horizontal outlet headers interfered with the burner registers and sleeve damper assembly.

2. Supply tubes feeding the second pass downcomer interfered with the burner barrels and register drives.

3. Two boiler-support diagonal braces [14WF158] were interfering with the outside pair of burners.

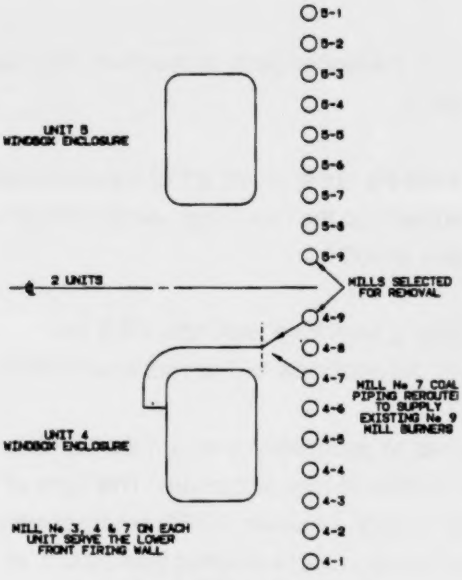
In addition to these major interferences, several other problems were discovered including conflicts with: a row of sootblowers; supply piping to the third-pass inlet headers; and windbox internal trusses and platforms. B&W also advised that with burners located higher up in the furnace, gas temperatures would be hotter in this area which might require moving the entire mix enclosure section of the furnace upward; B&W indicated that a full circulation study would be required. All of these problems stopped any further evaluation of Option (1).

PULVERIZER ARRANGEMENTS

Figure 9 shows the existing site general arrangement of pulverizers on Units 4 & 5. Burners on the furnace rear wall are fed by the outside mills # 1, 2, 8 & 9 while the center mills #3-7 supply coal to the front firing wall; mills #3, 4, and 7 supply the lower front wall. The obvious candidates for pulverizer removal, for converting to an eight (8) mill system design, were one of the three mills supplying the lower front wall. However, a thorough review by UE&C showed that the best mill for removal on each unit was mill #9. Removal of mills # 9 involved the least amount of burner piping changes and provided the following additional benefits:

- The common silo serving mills 4-9 and 5-9 could be removed from service. Maintenance and repair of this silo was always a problem since Units 4 & 5 were never scheduled for overlapping overhauls.
- Access for removal of roll-wheels on mill 5-9 was very tight due to the close proximity of cable trays.
- An alternate pathway would be available to the pulverizer alley for maintenance personnel and equipment access.

UE&C also reviewed the design feasibility of installing enlarged top housings/classifier assemblies on the MPS-89N pulverizers for capacity upgrading. The outline dimensions of the enlarged top housings were two feet higher and three feet larger in diameter than those of the MPS-89N mill. The focus of UE&C's review was to identify any major interferences with boiler structural steel, large high pressure piping, cable trays, or physical conflicts between adjacent mills. Results from this design review were as follows.


5-1
5-2
5-3
5-4
5-5
5-6
5-7
5-8
5-9
UNIT 5
WINDBOX ENCLOSURE
2 UNITS
MILLS SELECTED
FOR REMOVAL
4-9
4-8
4-7
MILL No 7 COAL
PIPING REROUTED
TO SUPPLY
EXISTING No 9
MILL BURNERS
4-6
4-5
4-4
4-3
4-2
4-1
UNIT 4
WINDBOX ENCLOSURE
MILL No 3, 4 & 7 ON EACH
UNIT SERVE THE LOWER
FRONT FIRING WALL

SITE GENERAL ARRANGEMENT OF PULVERIZERS
ON FOUR CORNERS UNITS 4 & 5

Figure 9

Several significant interferences were identified between the larger top housings and existing cable trays and structural steel. Specifically, pulverizers # 4-1 and 5-2 interfered with cable tray support steel and trays, which would require redesign of the cable trays system. Pulverizers # 5 on each unit interfered with horizontal structural steel necessitating that it be moved up 7'-6" to eliminate the problem. Other minor conflicts were noted. Nevertheless, none of these interferences were so severe as to preclude implementation of this design.

BURNER PIPING

In the cell burner firing arrangement, each pulverizer supplies coal to two (2), three-nozzle cell burners, one on each side of the division wall. As indicated by the number/letter designations in Figure 9, the pair of cells per mill are all non-symmetrical with respects to the division wall except for pulverizer #4. As a result, the heat release across the furnace is not uniform during startup or with any mill out of service except #4. In evaluating burner piping design for the new low-NOx burner system, two basic alternatives were available. Both were based on an 8 mill, 48 burner configuration. The first alternative was based on the maximum reuse of existing piping and routings. It involved replacing only the piping necessary to supply the relocated burners and to accommodate the tangential inlet connection on the FWEC low-NOx burner versus the center inlet on the B & W cell burners. Piping replacement for this alternative included:

(a) All burner piping above the feeder deck at the front and rear furnace faces. The quantity was estimated at 1050 ft.

(b) New burner piping from the outlet of mill #7 to connect with existing piping (from deleted mill #9) supplying burners on the rear firing wall as shown schematically in Figure 9. The amount was estimated at 400 ft.

(c) Sections of burner piping from front wall mills #3-6 below the feeder deck required by the new burner locations. An additional 250 ft. was estimated for this modification.

The second alternative was to completely redesign the burner piping to an arrangement where each pulverizer fired a horizontal row of burners. This type of design is standard for newer, wall-fired, circular burner boilers. However, UE&C emphasized the significantly increased complexity of this piping configuration and estimated that 3500 ft. of new, rerouted piping would be required.

The obvious operational advantage of horizontal firing is a uniform heat release across the furnace regardless of the number of pulverizers in service or their loading. Uniform heat distribution across the furnace during startups and at reduced loads with mills out of service minimizes FEGT imbalances and extremes in superheater-outlet tube metal temperatures, particularly during startups -- before a coolant steam flow is established in the superheater tubing. Nevertheless the initial cost differential projections by UE&C were $1.0 million per unit for upgrading to the horizontal firing arrangement.

APS Engineering further evaluated the differences between the two alternatives and discovered that Plant Maintenance was planning on replacing all of the existing bends and some sections of straight-run burner piping, due to severe erosion, during the next two annual overhauls. This fact substantially reduced the scope and cost differences between the two alternatives. Reassessment of alternative No. 1 showed that its total or combined burner piping replacement was around 2500 ft. when the maintenance scope was added. Total piping replacement for Alternate No. 2 remained unchanged at 3500 ft.

A more detailed cost evaluation also showed that UE&C's preliminary estimates of alternative No. 1 had not accounted for removal, handling, and reinstallation of existing piping below the feeder deck in order to install new front wall piping. This omission plus the added maintenance scope reduced the cost differences for upgrading to horizontal firing to $250,000 on Unit 4 and $400,000 on Unit 5. Additional design and construction factors favoring a complete burner piping redesign to horizontal firing were:

- Proper upflow flame rotation provided on all burners adjacent to the division- and side-walls.
- An existing lower elevation of horizontal burner conduits, with short radius elbows near the mill outlet, were eliminated.
- Piping fit-up and interface problems minimized.
- Speed and ease of erection improved.
- Eliminated the uncertainty about the condition of piping targeted for reuse and the potential for substantial, costly field piping fabrication.

PULVERIZER/BURNER CONTROLS

The existing Burner Management System for the cell burner array was designed with nine (9) identical burner-pair control logic sub-loops. Each sub-loop provides logic control on one pulverizer and its pair of cell burners for operation of:

- Ignitors

- Burner Air Registers (Not in Service)
- Pulverizer Outlet Isolation Valves
- Burner Impeller Position (Not in Service)
- Pulverizer Drive Motors
- Coal Feeders
- Mill Lube Oil System

Two gas ignitors are mounted between the closely-spaced nozzle openings on each of the 18 cell burners.

Installation of the new low-NOx burner system with its 48 circular burners (and individual ignitors) in a widened burner firing pattern more than doubled the I/O requirements of the Burner Management System. Since the existing system of electromechanical relays and timers was outmoded and had no expansion capability, it had to be replaced. APS Control-System engineers evaluated various options and selected a new, Bailey Net 90 microprocessor-based distributed Burner Management System.

ECONOMICS OF CAPACITY-UPGRADED PULVERIZERS

Both short and long-term economics were evaluated to determine the cost-effectiveness of capacity upgrading the MPS-89N mills. Since the new N-series mills were already installed on Unit 5 the modifications involved upgrades for Unit 4 and retrofitting on Unit 5. The estimated M&L cost to upgrade to larger top housings/classifiers and larger grinding zone elements on the Unit 4 mills was $400,000; however, the projected costs for retrofitting the Unit 5 pulverizers was $2.0 million. An additional $1.5 million was estimated to eliminate interferences and clearance constraints caused by the larger top housings and cover increased design engineering and construction inspection costs. Thus the total added capital costs for increased capacity pulverizers was estimated at around $4.0 million for both units.

The "savings" or return on this investment was the difference in energy production, and replacement power costs, provided by the upsized pulverizers. This difference was estimated at 26,600 MWH annually, or around $200,000 per year in the short-term. Long-term economics based on a present worth analysis of differential fuel costs showed a similar unfavorable "break-even" point at around 19 years.

SELECTED SYSTEM DESIGN

Based on the studies outlined above, and the successful pilot-scale comparative burner testing, in mid-1987 the owners of Units 4 and 5 approved the following boiler-plant design modifications for NOx control.

1. Deletion of one pulverizer from each unit and conversion to an 8-mill/48 burner configuration utilizing MPS-89N pulverizers and FWEC circular LNB.

2. Replacement of essentially all burner piping, except for straight runs along the sides of the boiler, to accommodate the revised burner pattern and provide horizontal firing on all pulverizers.

3. Replacement of furnace firing-wall tubing panels in the burner zone.

4. Installation of a new Bailey Net 90, programmable-logic distributed Burner Management System.

5. Addition of Forney SIE UV and IDD2 flame detectors for ignitor and main coal flame scanning.

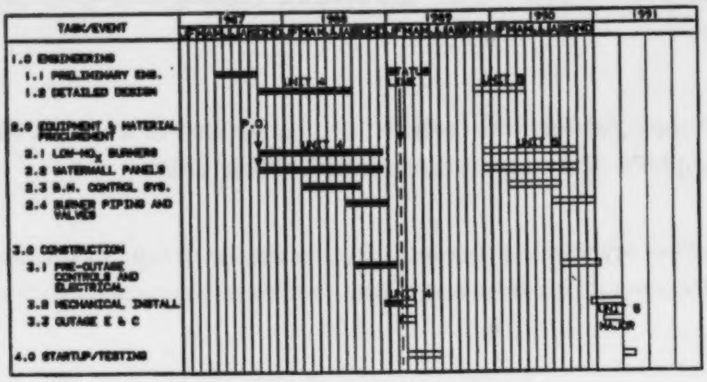
SCHEDULE AND COSTS

SCHEDULE

Detailed design engineering for the Four Corners Units 4 and 5 NOx Abatement Project began in September, 1987, shortly after project approval. APS' Generation Engineering staff performed all detailed engineering work. Initial work involved development of specifications and drawings for major equipment and materials procurement including the new burners waterwall panels, and Burner Management control system. The lead times for delivery of this principal equipment are shown in Figure 10 along with the spans and interfaces for various phases of design engineering, procurement, and construction; schedules shown for Unit 4 are "actuals".

To complete the detailed engineering phase of work on schedule, a project team of eight engineers (3 ME, 3 CSE, 2 EE and 1 C-S) and five designers were assigned full-time. An engineering Project Manager was also appointed to plan, coordinate, and direct work activities and monitor progress against the plan.

The magnitude and complexity of the project required that the construction work be planned around 60-day major Unit overhauls scheduled for the spring of 1989 (Unit 4) and 1991 (Unit 5).



SCHEDULE PLAN, NO$_X$ ABATEMENT PROJECT,
FOUR CORNERS UNITS 4 & 5

Figure 10

COST

The finalized, total cost estimate for retrofitting the new low-NOx burner system on Unit 4 is $17.5 million. Unit 5 projected costs are slightly higher due primarily to escalation. The finalized estimate is based on design engineering being 100% complete, and all equipment/material PO's and construction contracts awarded. Costs were distributed as follows for major elements of the project.

	Unit 4 Costs ($000)		
	Component	**Material**	**Labor**
1.	Burners & Scanners	4,640	950
2.	Burner Zone Tubing Panels	860	1,200
3.	Pulverizer/Burner Net 90 Conrol System	1,450	750
4.	Burner Piping, Hangers, Valves	1,600	1,500
5.	Structural Modifications and Platforms	225	500
6.	New Ignitors	155	906
7.	Furnace View Ports	140	120
8.	Removal of Abando		150
9.	APS Engineering & Construction Administration Labor		1,260

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REDUCTION OF NOX EMISSIONS FROM A 500MW FRONT WALL FIRED BOILER

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ABSTRACT

The Central Electricity Generating Board is committed to a policy of NOx emission reduction and to this end all coal fired 500-660MW(e) boilers in the UK will be converted to low NOx combustion systems before 1996. This paper reports the pilot conversion of a 'large burner' 500MWe front wall fired unit at Eggborough, England. The FWEC controlled flow split flame burner was used for this conversion and data are presented showing the NOx reduction effected and identifying the potential long term

problems of such a conversion when normal UK coal supplies are burned. A consistent NOx reduction of 40-45% has been shown.

The burners were installed in 1986 by Foster Wheeler Power Products and the boiler is constantly being monitored for resultant effects in a 3 year demonstration and proving period.

INTRODUCTION

The Central Electricity Generating Board (CEGB) has adopted a Low NOx Retrofit Programme in which all large coal fired boiler plant (500MWe and above) has been divided into four groups or 'families', based on similarities between the combustion system components involved. The boilers at Eggborough Power Station are included in Family 2, which comprises front wall fired furnaces incorporating coal burners of approximately 58MWt capacity.

Thus Boiler 2 at Eggborough is now the prototype unit for Family 2, and the experience gained during the three year post modification test programme could be directly applied to a further 11 boilers.

The purpose of the conversion is to assess the performance available from proven technology when applied to existing plant and to identify any operating or maintenance costs which may arise from the conversion. Of particular concern is the effect of NOx technology on plant which is firing United Kingdom (UK) coal with a significant chlorine content, and on plant which already suffers to some extent from fireside corrosion.

The ultimate aim is to provide plant which will comply with the European Economic Community (EEC) large plant directives, if and when these are fully ratified and accepted. Unit 2 at Eggborough has an estimated life expectancy of 25 years beyond 1988.

SYSTEM INTENT

The main intention of the retrofit was to establish the NOx reduction available from current combustion technology and to assess any additional plant operating costs incurred. To this end it was necessary to determine the performance and NOx output of unmodified plant, and No1 boiler at Eggborough was selected for this purpose. Because of the deterioration normal to a boiler as operating hours increase in the 38 months between overhauls, it is not possible to test the trial boiler "before and after" conversion, as the post overhaul performance differs substantially from that produced pre overhaul, such factors as casing duct work leakage affecting boiler performance considerably.

Boiler No1 (unmodified) and No2 (modified) were to be tested in the immediate post overhaul state and with the exception of course of the burners, were judged to be as nearly similar as practicable.

To summarise, the objectives of the tests were:

1) To minimise the NOx emissions from the modified boiler by careful optimisation of the system using the variables available.

2) To characterise and compare the performance of the modified and baseline units.

3) To assess the long term performance of the modified boiler by monitoring emissions and efficiency during normal commercial operation.

4) To accurately identify any operational and maintenance cost increase as a result of the modification.

CHOICE OF LOW NOX BURNER

Following an investigation of the available technology and detailed discussion with burner manufacturers, the Foster Wheeler Energy Corporation (FWEC) controlled flow split flame (CF-SF) burner was selected as a suitable burner for the prototype installation.

The main reason for this decision was that this design of burner had been installed and operating in large boiler plant for some years and had demonstrated NOx reduction of 50%+ at input sizes both smaller and larger than the 58MWTh/burner required.

Subsidiary reasons were that, on US coals at least, there were apparently few material or other burner problems experienced on front wall fired boilers.

PLANT DESCRIPTION

There are four 500MW(e) units at Eggborough Power Station, North Humberside. The boilers are of Foster Wheeler John Brown design, operating at 159 bars steam pressure (TSV) and 565/565 deg. C steam temperatures. The furnaces of each boiler were originally divided into 4 cells by a central water wall and two steam division walls. The steam division walls were truncated early in the station life (last unit was commissioned in 1969), leaving a furnace divided only by a central water wall. The boiler is fired by 24 coal burners arranged in three horizontal rows of 8 burners on the front wall. Air supply is via a common windbox. The pulverised coal is supplied by 6 Foster Wheeler D9 tube ball mills, each mill feeding four burners. Full load can be attained on 5 mills but it is normal to operate 6 mills for loads over 450MW.

The oil igniter burners are not original equipment, but are of tip shut off design by Spectus, and have been in service since 1972. Class G residual fuel oil is used at Eggborough for boiler warm up and coal ignition/stabilisation duties.

The modifications to the boiler and replacement of the burners on No2 unit were carried out by Foster Wheeler Power Products (FWPP). The burner registers were manufactured by FWPP to FWEC designs at the FWPP Hartlepool works, but the nozzle tip and coal distribution nozzle castings were made in the USA by FWEC and shipped to FWPP who completed the assembly. A considerable increase in quarl throat diameter was required by the CF-SF burner (43" compared with the 38" of the intervane turbulent burner) and this necessitated a large amount of boiler front wall tube work modification. Panels of 24 tubes each containing the tube sets for 3 burner quarls were shop fabricated and were installed complete. Eight such panels were required.

Also installed were 6 air ports complete with dampers, adjacent to the boiler sidewalls. These ports could not be installed in accordance with FWEC practice due to mechanical restrictions and were therefore located one on each burner horizontal centre line, the intention being to provide blanketing air for the boiler sidewall if required. The Eggborough boilers have a history of sidewall tube metal corrosion in well defined areas; this is countered by the extensive use of co-extruded boiler tube, the outer tube sheath being 25/20 Cr Ni stainless steel.

The FWEC CF-SF burner (1) consists of a register with radial inflow swirl vanes, which swirl all the air entering the burner, and an inner swirl vane system which swirls only the secondary air inside the secondary/tertiary flow divider.

The coal nozzle consists of a sliding tip and an outer nozzle (fabricated originally, but subsequently cast in later US installations: cast nozzles were adopted for Eggborough) which divides the fuel into four axial streams. The tip movement varies the amount of fuel admitted to an inner annulus and also to the four outer axial streams. In order to meet the 38 month component life requirement, FWEC modified these nozzles, substituting an annular conical outer nozzle containing four vanes which imparted swirl to the coal flow. With these nozzles installed target NOx reduction was not achieved and after a short period of operation, axial flow split flame nozzles were substituted with a significant improvement in performance. The boiler design did not readily lend itself to the installation of overfire air ports (lack of space above the top burner row). Because of the doubts regarding furnace corrosion and the heavy expense which would be incurred by an OFA installation it was decided not to fit such ports.

To provide additional security after a major change to the combustion system the burners were fitted with flame monitors of the Land Flamescan type which have proved successful in service, discriminating reliably between flames and background radiation levels. The flamescan system also proved useful in the coal flame optimisation process.

RESULTS

The evaluation of the low NOx system proceeded in stages as follows:-

1) The establishment of the baseline NOx and performance levels by tests on No1 soon after the outage of 1986. This unit was similar to No2, but unmodified as mentioned previously.

2) The optimisation and testing of No2 to establish the 'as converted' performance levels.

3) Further regular test work which would identify any deterioration in performance from No 2 as operating hours built up.

4) The establishment of operating costs both as efficiency losses and also as increased maintenance/component replacement levels resulting from the conversion.

FUEL

The normal Eggborough fuel supplies were used for the boiler test work, variations in fuel composition from test to test being identified by frequent sampling and analysis. On average the station is supplied by coal from up to 27 mines but an attempt was made to use only coal from 2 or 3 sources during boiler tests.

A typical (as received) test coal analysis was:-

Total moisture	10%
Volatiles	27%
Ash	16%
Fixed Carbon	47%
C.V. (kJ/kg)	25.5
Nitrogen	1.3%

INSTRUMENTATION

Optimisation Instrumentation (Low NOx Conversion)

As the unit was basically a prototype it was considered necessary to install the FWEC required level of post economiser gas analysis instrumentation. FWEC consider this essential to the combustion system optimisation process and therefore a 32 point probe sampling system was installed from which O_2, CO and NOx levels could be measured at evenly distributed points across the economiser exit ductwork.

Test Instrumentation (Reference and low NOx boilers)

The formal boiler trials were made using gas analysis instrumentation in the post ID fan ductwork, oxygen (paramagnetic), carbon monoxide (infra red) and NOx (chemilumincescent) gas analysers were used at this point. Carbon in dust determinations were made by the normal station processes. Several hundred items of plant performance data were logged at minute intervals during each test using the station mainframe computer. The data were transferred to hard disc for subsequent off-line analysis.

UNMODIFIED BOILER NOX EMISSIONS

As mentioned previously, No 1 boiler was selected as the datum unit and was tested in early 1986. The test programme was aimed at establishing the basic combustion and heat transfer characteristics of the boiler whilst recording NOx levels. Most of the tests were conducted at or near 500MWe.

The NOx recorded levels are shown in Figure 1 and are corrected to 3% oxygen dry as are all NOx levels quoted in this paper.

The average NOx level from the load range 477-503MW was 748vpm, but some variation was found with time due to fuel variation and boiler casing deterioration. The maximum boiler load is controlled by the draught plant capability which is indicated by the CO level in the gases at the ID fan.

In conjunction with the exhaust gas analysis, p.f. distribution and furnace wall gas analyses were performed, as were carbon in dust level determinations.

The p.f. distribution was found to be good, but strongly reducing conditions were found close to the boiler sidewalls. CO levels of up to 4.9% being measured with all mills in service. The rear wall CO levels were found to be low, with a maximum of .42% measured.

NO 2 BOILER OPTIMISATION 1986 (Mk I BURNER)

The optimisation after conversion in Autumn 1986 was carried out by FWEC and FWPP commissioning engineers, with close CEGB assistance.

FWEC attempted to follow the procedure now well documented in their publications. However, certain aspects of the normal process were not possible because it was discovered that the burner register pressure loss was too high. The station has been proved to be short of fan power over the years as the original plant did not possess adequate margins. Efforts have been made to remedy the situation by tipping impellers and various other draught plant modifications. No 2 is now limited to 485MW in the summer and possibly 510MW in the winter. At the moment the FD is the limit, but as the unit progresses through the 3 years between outages and the casing leaks increase, the ID fan limit may be reached, although this now appears unlikely. (The 500MW unit load is now expected, following turbine steam inlet modifications which have restored the output to design levels after some years of a 450MW turbine restricted rating).

In accordance with normal FWEC practice the sleeve dampers were adjusted in an attempt to balance the O_2 and CO across the furnace, but with detrimental effect.

All the trimming was therefore effected by the use of the moveable coal tip, together with secondary and tertiary air vane adjustment.

However, it should be noted that the burners were very stable and produced only small levels of side and rear wall CO in this state of modification. The settings were Outer Air Register (OAR) 50-60%, and the Inner Air Register (IAR) 25%.

The initial measurements after the optimisation phase indicated a NOx reduction of 25-30% when compared with the unmodified unit. This performance was disappointing and it was decided not to test the boiler fully before the further modification.

Following these results, FWEC decided to substitute the split flame tip. The change, however, was not possible until August-September 1987 and then it was made in two stages as replacement components became available.

NO 2 BOILER OPTIMISATION AND TESTS NOVEMBER 1987 (Mk II burner)

Immediately after the full complement of split flame tips were installed the unit was re-optimised, but as the air register was not modified in the conversion the pressure drop limitation remained. Well over 100 tests were made during the optimisation process. The resultant settings for the outer air registers were: 55deg. sidewall burners and 45deg. otherwise. The majority of inner air registers were closed i.e., maximum swirl. All sleeve dampers were fully open.

The NOx production did not appear to be significantly affected by burner adjustments although flame stability certainly was affected. The optimised settings quoted here gave satisfactory stability, but did increase the pressure drop, again causing a load restriction.

NOX EMISSIONS

NOx levels were found to be substantially lower than those produced in the "interim" phase and 420vpm or below was recorded at 500MW as shown in Figure 2. This represents a NOx reduction of 43%, and this has been maintained or bettered by the boiler in subsequent operation.

Following optimisation, the boiler was subjected to an intensive test series, largely at high loads. Draught plant restrictions prevented exploration of the NOx/excess air relationship at 500MW and it was necessary to establish the excess air effect at 440-460MW, but with all mills in service the technique was simply to vary the total airflow to a fixed fuel input unit load at a constant furnace suction to prevent changes in boiler air ingress. The effect on NOx emission for both the Low NOx and unmodified boilers is shown in Figure 3.

During these tests the carbon in dust values were also measured by analysing samples obtained by isokinetic sampling at the precipitator inlet. These results are shown in Figure 4. The relationships shown in Figures 3 and 4 enabled the costs in terms of enhanced carbon in dust levels, to be evaluated on the basis of test data. Operation to a NOx level of 390vpm would be expected to produce a three-fold increase in the carbon in dust level.

Comparison of Figures 2 and 3 suggests that an increase in unit load from 462MW to 500MW would be expected to increase NOx production by about 8% at the design excess air level.

OTHER EFFECTS OF THE LOW NOX MODIFICATION

As mentioned earlier, the Eggborough boilers have a history of fireside corrosion which has been countered by the selective use of coextruded tube. The areas subjected to high rates of corrosion can usually be detected by high (>1%) CO concentrations at the furnace walls. The effects of the low NOx modification in these retrofit circumstances have been to greatly increase the area of furnace wall subject to reducing conditions. In fact, the boiler walls are now affected by reducing gases on both side and rear walls. CO levels of up to 9.0% were measured at the rear wall. No furnace tube failures have occurred, however, but accurate measurement of the metal loss rates awaits the examination planned for the scheduled unit shutdown in 1989.

The low NOx modification would be expected to produce some change in the heat transfer pattern within the boiler. Compared with the unmodified units, the modified boiler shows a reduction in heat absorption by the furnace and an increase in heat absorption within the convective zone. Whilst generally beneficial, in that a problem in maintaining final steam temperatures has been eased, the use of attemporation is very dependent on loading pattern and fuel quality.

A number of erosion failures of the burner core tube near the sliding tip have recently been experienced, 22 of the 24 core tubes having been holed as a result of p.f. erosion. These failures have occurred after 16000 hours operation, 9,500 hours since the nozzle change, well short of the 25,000 hours (38 months) specified. The outage period in the USA is normally 12 months and thus there is limited experience within FWEC of burners running for longer periods without examination and weld repair if necessary. A modification involving higher grade erosion resistant materials is being developed; meanwhile temporary repairs are being made on a piecemeal basis to carry the unit through to the 1989 outage.

CONCLUSIONS

1) The FWEC CF-SF Low NOx coal burner has been in operation on a 500MW boiler at Eggborough for three years producing a consistent reduction of 40-45% in NOx emissions compared with an unmodified unit.

2) An increase in carbon in dust levels has been observed dependent on the level of excess air employed and NOx reduction sought.

3) Changes in the heat transfer pattern in the boiler have been measured. Final steam temperatures can be achieved more readily on the unit, than was the case prior to the modification.

4) Significant deterioration in furnace atmospheres near the water walls have been found but no tube failures have occurred.

5) Burner core tube metal erosion failures have occurred at 16,000 hours, well short of the specified burner component life (38 months = 25,000 hours). Solutions to the problem are being engineered.

6) During the period since conversion, Unit 2 has operated as required by Grid Control except for periods during testing and modification. No major changes in operating procedures were necessary.

ACKNOWLEDGEMENTS

The authors wish to express their gratitude to the Station Manager and staff of Eggborough Power Station for their assistance in all stages of the execution of this project.

This paper is published with the permission of the Central Electricity Generating Board.

The work described in this paper was not funded by the US Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

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1. Vatsky, J. (1982) High Capacity Low NOx Coal Burner for Retrofit and New Units. Power Engineering. January 1982.

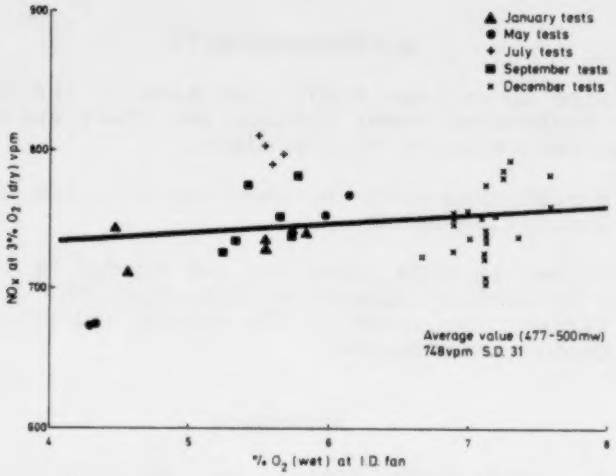

Figure 1 NOx emissions from Unit 1 Boiler (unmodified) with 6 mills in service at Unit loads of 477 to 503MW.

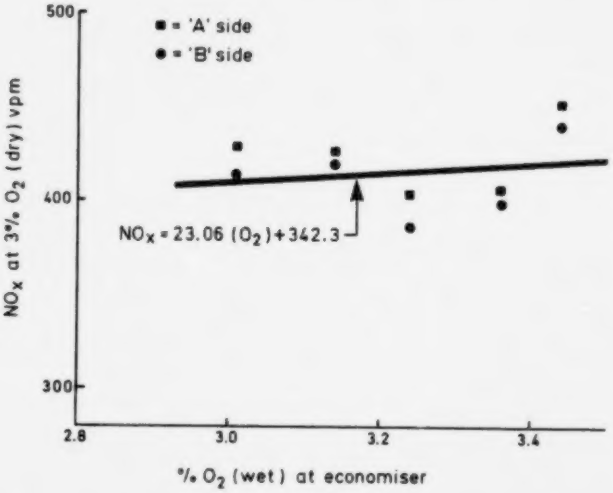

Figure 2 NOx emissions from Unit 2 Boiler (Low NOx) at different excess oxygen levels.

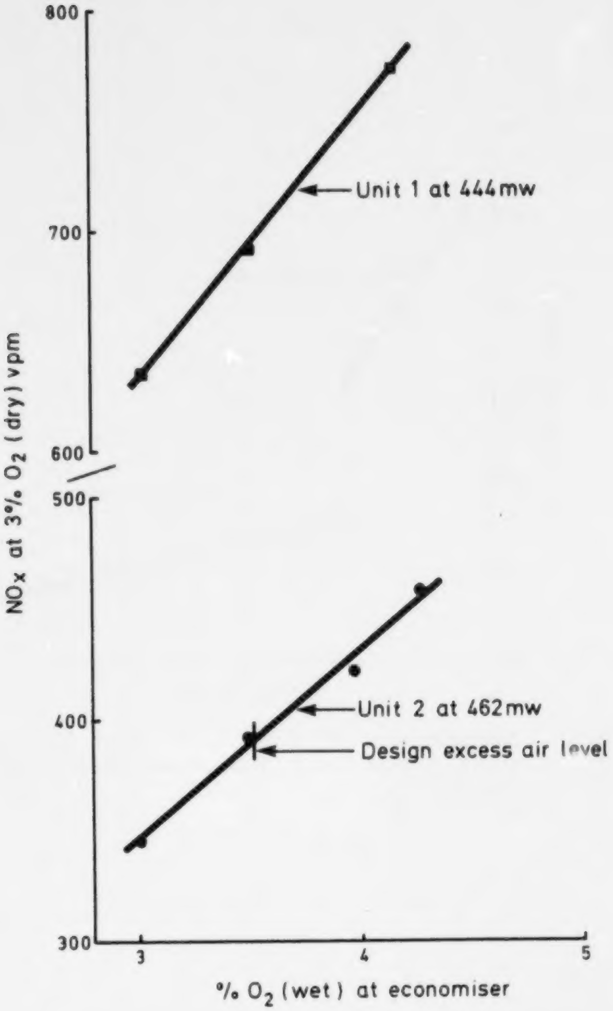

Figure 3   Comparison of NOx emissions from Unit 1 and Unit 2 boilers at various excess oxygen levels.

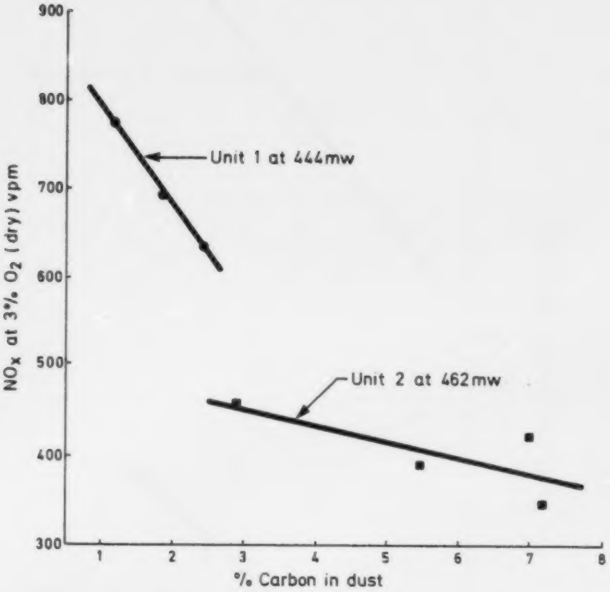

Figure 4 Comparison of carbon in dust levels from Unit 1 and Unit 2 boilers with emitted NOx level.

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NO_x EMISSIONS RESULTS FOR A LOW-NO_x PM BURNER RETROFIT

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ABSTRACT

The retrofit application of combustion modifications to pre-NSPS boilers has received widespread attention by many electric utilities as a result of environmental pressures to further reduce national NO_x emissions. Although pilot-scale tests suggest that such retrofits are promising, full-scale demonstrations are an essential step in determining actual commercial viability. Boiler emissions results are reported for the first of several full-scale low-NO_x demonstration projects now being conducted by the Electric Power Research Institute (EPRI). In this project, the PM low-NO_x firing system was retrofit to a 400 MWe tangentially-fired boiler at Kansas Power and Light's Lawrence Energy Center Unit 5. The PM firing system included low-NO_x burners and two levels of overfire air.

Test results with a low sulfur bituminous coal indicate that NO_x reductions of 30 - 50% were achieved at high loads (200 - 335 MWe) under carefully controlled test conditions. Overfire air was found to be the dominant parameter in achieving these NO_x reductions. Post-retrofit NO_x emissions levels varied from 180 ppm to 400 ppm across the load range in comparison to tuned baseline (pre-retrofit) emissions of 350 ppm to 400 ppm. At low loads (less than 200 MWe), NO_x reductions diminished. For the higher NO_x reductions, O_2 requirements increased by up to one percent. No change in unburned carbon or CO emissions was observed. Long-term tests are now underway to evaluate emissions performance under normal day-to-day operating conditions.

INTRODUCTION

Nitrogen oxide (NO_x) emissions from new coal-fired utility boilers have been regulated since the passage of the Federal Clean Air Act and establishment of the New Source Performance Standards (NSPS) in 1971. Utility boilers, which represent about one-third of the total U.S. NO_x emissions, may be required to further reduce NO_x emissions. Because almost two-thirds of these utility NO_x emissions result from the pre-NSPS coal-fired boilers, the Electric Power Research Institute (EPRI) and its member utilities are sponsoring an extensive program to evaluate and demonstrate low cost, retrofittable NO_x controls for pre-NSPS coal-fired utility boilers. The low-NO_x burner retrofit project at Lawrence Unit 5 is one element of this program.

excellent burnout characteristics, the low heating value limits the maximum load to approximately 335 MWe. A typical coal analysis is given below:

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	12.79	xxxxx
% Ash	8.84	10.14
% Volatile	36.73	42.12
% Fixed Carbon	41.64	47.74
	100.00	100.00

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	12.79	xxxxx
% Carbon	60.60	69.49
% Hydrogen	4.38	5.02
% Nitrogen	1.29	1.48
% Sulfur	0.91	1.04
% Ash	8.84	10.14
% Oxygen	11.19	12.83
	100.00	100.00

Lawrence Unit 5 is generally typical of other pre-NSPS CE designs which was an important factor in its selection. Specifically, the furnace dimensions are 50'-8" wide by 40'-2" deep and 110' high yielding a volumetric heat release and plan area representative of other CE units of similar capacity. However, the net heat input per plan area is near the low end of the range of most CE units of similar vintage when firing at a derated capacity of 335 MWe with the low sulfur Wyoming coal. This reduced heat release rate influenced the baseline NO_x emission which were 10 to 15% lower than many other large coal-fired CE units.

PM Firing System

The PM firing system included new windboxes with integral ("close coupled") OFA ports, separate compartments for additional ("separated") OFA, a new secondary air control system, and a partial replacement of the coal piping. Each of the four new windboxes contain five elevations of PM burners with each burner consisting of a fuel-rich and fuel-lean coal nozzle. The PM burner system achieves low-NO_x emissions by controlling the local stoichiometry in the near-burner region where coal ignition and combustion of the volatile matter occurs. Fuel-rich and fuel-lean combustion zones are created at the burner front by aerodynamic segregation of the pulverized coal in the approaching coal pipe as shown in Figure 2. The close coupled overfire air ports in combination with the two PM coal nozzles per burner elevation results in a taller windbox than the original windbox as shown in Figure 3. Separated overfire air ports were installed approximately six feet above the new windboxes as shown in Figure 4. The burners and both sets of OFA ports can be tilted $\pm 30^0$ with respect to horizontal. The separated OFA ports also have yaw tilt capability of $\pm 10^0$ relative to the firing circle. The PM firing system is described in more detail in References 1, 2 and 3.

Gaseous Emissions Measurement System

Gaseous emissions measurements were made for NO_x, O_2, CO, CO_2, and SO_2 using the continuous gas analysis system shown in Figure 5. A total of ten sample probes were installed in each economizer exit duct to evaluate the combustion uniformity at the boiler outlet. Flow meters in the test trailer were adjusted to achieve balanced flow from all 20 sample probes. The gas analyzers used at Lawrence 5 are listed in Table 1.

Retrofit low-NO_x combustion systems are based on the same concepts currently being applied to new units. However, new boilers have larger furnaces which are designed to accommodate the operating characteristics of low-NO_x combustion systems. A major element of the EPRI demonstration program is to determine the impact of low-NO_x operation on the performance and maintenance requirements of boilers with typical pre-NSPS furnace designs.

PROJECT OBJECTIVES AND SCOPE

The EPRI demonstration project at Lawrence Unit 5 involved the retrofit of the PM low-NO_x firing system on a 400 MWe tangentially-fired boiler. The primary objectives were to assess the overall performance and reliability of the PM system and to determine the maximum NO_x reduction potential without an adverse impact on plant operations. Other issues besides emissions were addressed including boiler thermal efficiency, steam temperature control, furnace exit temperature, slagging and fouling, and operating flexibility.

The full-scale evaluation of the retrofit PM burner system consists of three major testing activities: (1) Pre-Retrofit Baseline Testing; (2) Post-Retrofit Low-NO_x Testing; and (3) Long-Term Evaluation.

Pre-retrofit baseline testing was conducted to determine the emissions and boiler performance of the existing Combustion Engineering (CE) burners. Post-retrofit tesing focused on characterization of the PM burner emissions and performance with and without overfire air (OFA). Finally, optimization tests were completed in preparation for a six to eight month long-term evaluation which was initiated in January 1989. The long-term tests will evaluate day-to-day variations in emissions and boiler performance during normal load dispatch operations as opposed to the carefully controlled conditions estabilshed during the short-term NO_x characterization tests. This paper discusses the results of the emissions tests conducted by Fossil Energy Research and Energy Systems Associates up to the beginning of the long-term tests (EPRI RP 2916-3). The PM firing system retrofit and evaluation of boiler thermal performance was performed by CE under separate contracts (Reference 1, 2, 3).

Long-term day-to-day evaluation of the PM system and extrapolation of results to the pre-NSPS tangential-fired boiler population will be completed in 1989 and reported subsequently. As such, while the authors have attempted to generalize results obtained to date, some results may be specific to Lawrence Unit 5.

SYSTEM DESCRIPTION

The unit selected for retrofit with the PM low-NO_x firing system is the Kansas Power & Light Lawrence Energy Center Unit 5 located in Lawrence, Kansas. Unit 5 is a tangentially-fired boiler rated at 400 MWe (2,805,000 lb/hr steam flow at 1005°F and 2620 psig, with 1005°F reheat). The single furnace design is fired from the four corners at five burner elevations for a total of twenty pulverized coal burners; see Figure 1. The original burners were conventional CE design with ±30° tilt for reheat steam temperature control.

The boiler was designed to burn a Midwest (Kansas) high volatile A bituminous coal with a heating value of 12,750 Btu/lb. However, the coal now being fired is a high volatile C bituminous coal from Wyoming's Powder River Basin having a heating value of 10,580 Btu/lb. Although this coal is very reactive and yields

GASEOUS EMISSIONS INSTRUMENTATION

Species	Analyzer	Analyzer Method
NO_x	Teco 10	Chemiluminescent w/ss converter
O_2	Teledyne 326	Electrochemical
CO/CO_2	Horiba PIR2000	Nondispersive infrared
SO_2	Western Research 721 A/D	Nondispersive ultraviolet

BASELINE TEST RESULTS

The baseline pre-retrofit test series characterized the emissions and performance of the original equipment burners for direct comparison to the PM firing system that was subsequently installed. Baseline boiler performance was monitored by examining key characteristics such as 1) combustion efficiency (CO emissions, fly ash carbon content and excess air level), 2) the ability to maintain the proper superheat and reheat steam temperatures, 3) fouling or slagging in the furnace or convective section, 4) radiant heat flux and 5) other emissions.

NO_x emissions from a tangentially-fired boiler are affected by a variety of operating parameters including: excess air, load, burner tilt position and secondary air damper settings. Baseline testing of Lawrence Unit 5 under load following conditions revealed a substantial variability in NO_x emissions over a one week test period. An example of this variability for a typical weekday is illustrated by the solid data points in Figure 6. Differences in operator preference for excess air level and secondary air damper settings were the primary cause of the wide NO_x emissions range. The effect of excess air variability is particularly evident at low loads, where high excess air levels are often utilized to maintain minimum air flow, windbox pressure or adequate steam temperature.

The tuned performance data in Figure 6 represents the range of NO_x emissions resulting from operation with the O_2 level adjusted for efficient operation and uniform fuel/air flow to the boiler using the extensive set of gaseous instrumentation installed for the test program. With tuned operation, emissions were relatively insensitive to boiler load; a characteristic exhibited by many tangentially-fired boilers. In addition, the Wyoming coal exhibited very good burnout characteristics with fly ash carbon content remaining well below 2% and typically of the order of 0.5%.

Secondary air damper settings had a significant influence on NO_x emissions at higher loads. Full load NO_x emissions could be varied from 250 ppm to 425 ppm at 3% O_2 by adjusting burner damper and tilt settings as shown in Figure 7. Lowering the burner tilts and increasing the burner zone fuel/air mixing increased the NO_x emissions by 16% relative to the tuned performance baseline conditions (-14° burner tilt and normal fuel/air mixing). Conversely, a 30% NO_x reduction was attained by biasing the secondary air flow between burner elevations plus adjusting individual dampers to minimize fuel/air mixing. No adverse impact of this operating mode could be discerned based upon furnance flame zone and inlet convective section obervations, gaseous emission measurements, and boiler performance (load, steam temperature, etc.). Although the substantial NO_x reduction achieved with the original equipment burners illustrates the potential of operational combustion modifications with little or no hardware expense, the reduction that can be achieved on other units will depend on the boiler design, coal type, and operating practices.

POST-RETROFIT TEST RESULTS

Emissions Characterization/Optimization

The post-retrofit test program included PM firing system emissions characterization tests and optimization tests. The characterization tests defined the relationship between the PM firing system emissions and a number of boiler operating parameters including:

- load
- O_2 level
- burner tilt
- OFA flow
- primary and secondary air damper settings
- windbox/furnace differential pressure
- OFA tilt (vertical and horizontal)
- OFA injection (port) location

The characterization tests also established a satisfactory operating envelope for the PM firing system that was used in defining subsequent optimization tests and the assessment of potential application to other tangentially-fired units.

NO_x emissions data from characterization tests comparing the original equipment (baseline) and the PM burners operating without OFA are summarzied in Figure 8. The objective of these full load (300 MWe) tests was to isolate the PM burner effect from the OFA staged combustion effect by making a direct burner-to-burner comparison. An average NO_x reduction of approximately 40 ppm or about 10 to 15% was measured. However, since the PM burner was designed to operate with the OFA ports open, these tests without OFA may have resulted in non-ideal burner throat velocities and local air/fuel ratios which could alter NO_x emissions.

Subsequent tests were conducted to determine the NO_x dependence on the overfire air flow rate (expressed as a percentage of the total combustion air flow). Overfire air flow was estimated by damper position and flow area calculations since direct measurement of both "close-coupled" and "separated" OFA flow was not possible. Test results for a typical 300 MWe firing configuration are shown in Figure 9. A NO_x reduction of 70 ppm occurred for approximately every 10% increase in OFA flow rate. OFA flow rates greater than 20% resulted in NO_x levels less than 200 ppm with a maximum NO_x reduction of over 50% obtained with maximum OFA (estimated to be above 25%). Figure 9 clearly shows the dominance of the OFA system in reducing NO_x emissions. Approximately 80% of the PM firing system NO_x reduction is attributable to overfire air which emphasizes the need for a well designed and flexible OFA system, possibly with booster fans and separate ducting in some applications. This system should include provisions for the direct measurement of OFA flow rate and fine tuning of the OFA system to accommodate site specific constraints.

It should be emphasized that the absolute emission levels shown in Figure 9 are specific to the Lawrence 5 boiler firing configuration and coal characteristics for steady state and carefully controlled operating conditions. An adverse impact on boiler performance and efficiency can result when operating at a high OFA flow rate to achieve minimum NO_x emissions.

The NO_x emissions characteristic of the PM firing system is influenced by a number of interdependent parameters which affect OFA mixing and heat release in the upper furnace region. An important element of the emissions characterization testing was a parametric investigation of other secondary operating parameters such as burner tilt, OFA tilt, and burner damper settings. Although burner tilt is primarily used to regulate reheat steam temperature and cannot be directly controlled to minimize NO_x emissions, it was important to define its influence. The relative angle between the burner flow and the OFA flow affects NO_x emissions, the minimum O_2 or smoke threshold, boiler efficiency and the uniformity of O_2 at the economizer outlet. As the angle of separation between the OFA and the burner tilts increased, the NO_x emissions decreased as shown in Figure 9 for a series of full load, high OFA flow tests. A more effective staged combustion condition occurs with a large separation angle which delays the mixing of the OFA flow and main burner flow. More importantly, the data indicates that little additional NO_x reduction occurs when the OFA tilt is raised above +10° for a burner tilt of -14°, typical of full load pre- or post-retrofit operation. However, the data in Figure 10 is presented for a specific O_2 of 3.5% and does not reflect the impact on minimum O_2 and boiler efficiency. Large OFA to burner separation angles adversely impacted the smoke point and combustion uniformity at the boiler exit which partially offset the gains in NO_x. This trade-off between NO_x, minimum O_2, and combustion uniformity can become an important issue depending upon whether a unit is equipped with motor driven OFA tilts. A unit with motor driven OFA tilts would provide the opportunity to maintain a desired angle relative to the burner flow as the burner tilts moved to control reheat steam temperature across the load range. With mechanically operated OFA tilts, one fixed position must be selected as a compromise between NO_x emissions, minimum O_2, combustion uniformity and boiler efficiency across the load range of the unit.

The nonuniformity in combustion noted previously was most evident at high OFA flows and occurred in two different forms. A large difference or "split" developed between the north and south furnace halves exceeding 2% in some instances compared to nominal differences of less than 1%. The split was occasionally accompanied by an oscillation in the O_2 level that required above average settings to avoid smoking. The O_2 oscillations were as large as 1.5% O_2 about the mean and sometimes caused smoking on the furnace half with the lower O_2. As a result, an above average O_2 was required to preclude smoking during these oscillations. On several occasions, testing was aborted due to this unexpected behavior. Typical O_2 fluctuations during normal operation were 0.2 to 0.5% O_2 (peak-to-peak).

The O_2 nonuniformity and oscillation appears to be associated with a large separation angle between the OFA flow and the burner flow which typically occurs as load increases and burner tilts rotate down. However, the exact cause of the O_2 split and oscillation is not fully understood. It is believed to be related to changes in upper furnace mixing patterns brought about by the overfire air. Reducing the overfire air flow and raising the O_2 level usually reduced the magnitude of the fluctuations and alleviated the smoking. An O_2 split of up to 1.7% was occasionally noted with the original equipment burners as the burner tilts varied. However, the O_2 fluctuations appear to be only associated with the use of overfire air. Long-term testing is expected to provide more insight regarding the day-to-day impact of this behavior. Operational adjustments to overfire and O_2 level are occasionally required, but it should be noted that the unit's ability to meet load demand has not been compromised.

The optimization phase of the post-retrofit test program examined trade-offs between NO_x emissions parameters (such as OFA flow) and boiler performance parameters (such as operating O_2 level, boiler efficiency, carbon utilization, CO emissions, steam temperature control, and dynamic boiler response). The objective was to define a long-term operating mode that minimized NO_x emissions with little or no degradation in unit performance. One of the important trade-offs with the current low-NO_x firing system is the dependence of the minimum O_2 operating point (i.e. smoke threshold) on the overfire air flow rate. A series of tests was conducted at 300 MWe to define this dependence which is shown in Figure 11. The family of slanted lines define the NO_x vs. O_2 characteristic for various amounts of OFA flow (0, 7, 15 and 27%). The lowest NO_x level that could be achieved at each OFA flow was limited by the minimum O_2 or smoke threshold indicated by the cross hatching. A significant NO_x reduction occurred with increasing OFA offset by only a minor increase in minimum O_2 ($<0.5\%$) until the OFA flow reached approximately 20%. At higher OFA levels, the NO_x reduction benefits diminish as the minimum O_2 increases. In addition, a decrease in boiler efficiency also occurs with the increased minimum O_2. For example, the one percent increase in minimum O_2 as the OFA increased from 0 to 27% OFA represents an efficiency loss of approximately 0.4%.

The typical minimum O_2 characteristic shown in Figure 11 is dependent upon boiler load, coal properties, firing configuration, and other boiler operational parameters (tilt, etc). All of these factors must be considered in establishing the recommended minimum O_2 and associated nominal O_2 operating level. In some cases, it may eventually become necessary to utilize very high OFA flows (depending upon future regulations) with some sacrifice in minimum O_2. Other factors that must be considered involve flame detection and safety considerations, carbon carryover in the ash, ash disposal/sale requirements, etc. OFA testing at Lawrence Unit 5 was not pushed to these limits because of the adverse impact on boiler efficiency and fuel consumption.

Overall NO_x Reduction Potential

A summary of pre-and post retrofit NO_x emissions over the load range under tuned and carefully controlled conditions is shown in Figure 12. Typical full load (300-320 MWe) post-retrofit NO_x emissions were 180 to 225 ppm. This represents a 30 to 50% reduction relative to the pre-retrofit baseline. As shown in Figure 11, maximum NO_x reductions were achieved at the expense of increased O_2 of up to 1.0%.

Similar comparisons at 200 MWe indicate a 25 to 40% reduction in NO_x relative to the pre-retrofit baseline. However, optimum conditions during normal operation will require automatic OFA tilt.

While testing focused on high load conditions, low load test results suggest little or no NO_x reduction is achieved below 200 MWe. This is believed to be caused by one or more of the following: 1) decreased OFA flow and penetration; 2) minimum air flow stops on the combustion controls; 3) increased O_2 requirements; and 4) non-optimum OFA tilt position.

Data generated during the characterization and optimization testing was used to define a long-term firing practice. Systems performance will be evaluated over 6-8 months beginning in January 1989 based on continuous emission monitoring data, utility operating experience, and occasional repeat performance tests. Boiler fireside inspections will be made. Finally, an economic feasibility study which will extrapolate/generalize results for the pre-NSPS coal-fired population will be conducted. Results of these activities will be presented separately.

PARTICULATE EMISSIONS DATA

Particulate emissions measurements at Lawrence Unit 5 included total particulate, ash carbon content (loss on ignition or LOI), particle size distribution, fly ash composition, and fly ash resistivity. Comparisons were made between the particulate emissions with the original equipment burners and the PM firing system. The primary objective of these measurements was to determine if the particulate emission characteristics with the PM firing system had changed in any manner that could affect the performance of a particulate control device. Although these measurements were made upstream of the wet scrubber at Lawrence 5, data was gathered to allow an assessment of the impact (if any) on the collection efficiency of an electrostatic precipitator (ESP). The results of the LOI, total particulate, and particle sizing tests are presented below.

For both the baseline and post-retrofit tests, carbon content of the fly ash remained low. Average carbon content for the baseline full load particulate tests was 0.4%, while the average for the post-retrofit, full load tests was 0.3%. These very low values indicate essentially complete combustion with both types of burners reflecting the excellent burnout characteristics of the Wyoming coal.

Total particulate tests obtained during baseline operation showed an average of 4.0 grains/dscf ash loading, while data from recently completed post-retrofit tests averaged 2.7 grains/dscf. The results indicate that particulate emissions were lower during the post-retrofit tests compared to the baseline tests. Further analysis of these results is planned once final post-retrofit coal analyses are completed.

The primary focus of the particle sizing tests was on the fraction of particles smaller than 1 micron, since these are the particles that are most difficult to collect with an ESP. Particle size tests were performed using both a cascade impactor and an electrical aerosal analyzer (EAA). The impactor sizes particles aerodynamically with eight cut sizes from approximately 0.3 to 10 microns The EAA sizes particles according to their electrical mobility and has an effective measurement range of 0.03 to 1.0 microns. The results of the cascade impactor tests indicate that no significant change occurred in particulate in the range of 0.3 to 10 microns. Preliminary results from recent EAA measurements suggest that fine particulate emissions below 1.0 microns may be as much as four to five times higher for low NO_x firing than with the original equipment burners. This result is contrary to prior correlations relating increased fine particulate with higher NO_x emissions. However, little or no sub-micron particulate data for low-NO_x burners is available for comparison to the Lawrence 5 data. Further analysis of the EAA ash samples and comparison to pilot scale fuel rich low-NO_x particulate data are planned.

CONCLUSIONS

To date, the evaluation of the emissions and performance characteristics of the PM firing system under short-term, carefully controlled conditions has been completed. While further work is planned, valuable insights on the potential retrofitability of this system has been gained. Key results follow:

- NO_x reductions of 30 to 50% were achieved with the PM firing system at high loads (200 - 335 MWe) under controlled test conditions.

- While only limited low load tests were conducted, little or no NO_x reduction was measured under these conditions.

- Overfire air is the dominant factor in the NO_x reductions achieved. Specifically, about 80% of the total NO_x reduction appears to result from OFA. As a result, design of the OFA system is critical and provisions for site specific fine tuning of the OFA flow and upper furnace mixing are recommended.

- For Lawrence Unit 5, typical full load NO_x emissions with 20% overfire air were 180-200 ppm at an average operating O_2 level of 3.5% and 200-225 ppm at 4.0% O_2. Further NO_x reductions were achievable with greater OFA flow rates of up to a maximum of 25%. For these conditions, minimum O_2 levels were increased by up to 1% resulting in a reduction in boiler efficiency.

- The minimum O_2 level for the PM firing system was approximately 0.5 to 1.0% O_2 higher than the original equipment burners.

- Total particulate emissions and ash carbon content were relatively unchanged while burning a very reactive low sulfur mid-western coal.

The long-term PM system evaluation, now being initiated, will define: 1) achievable, day-to-day NO_x reduction levels; and 2) boiler performance impacts under normal load dispatch conditions. These results, together with a planned economic feasibility study, will be used to formally extrapolate the results obtained at Lawrence 5 to the pre-NSPS pulverized coal, tangential-fired boiler population.

Acknowledgements

The authors acknowledge Mr. Preston Tempero, Plant Manager and the rest of the Lawrence Energy Center personnel for their cooperation and assistance in obtaining the resulted presented. The technical support and cooperation of Combustion Engineering is also acknowledged.

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2. M. McCartney. "Manufacturer's Update on NO_x Control Technology." Proceedings: 1989 EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, San Francisco, CA.

3. P. Tempero. "Installation and Operation of Low NO_x PM Burners." Presented at the Fifty-ninth Annual Engineering Conference of Missouri Valley Electric Association, Kansas City, MO, March 1988.

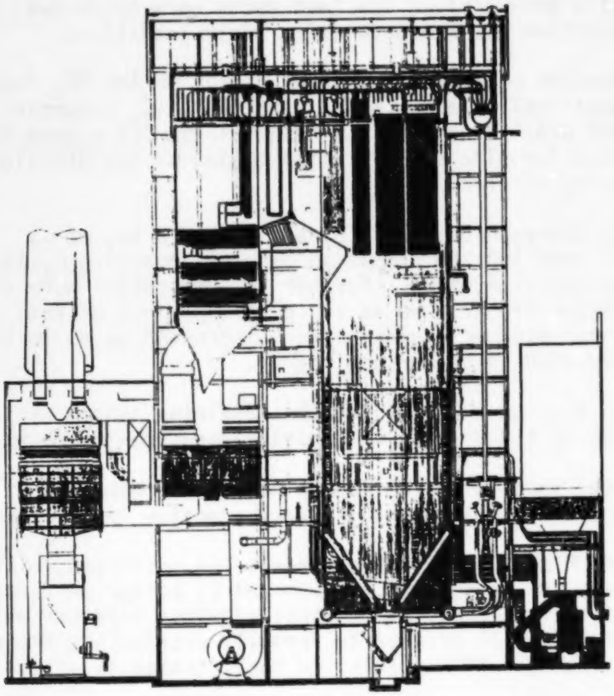

Figure 1. KPL Gas Service, Lawrence Unit 5 - 400 MWe

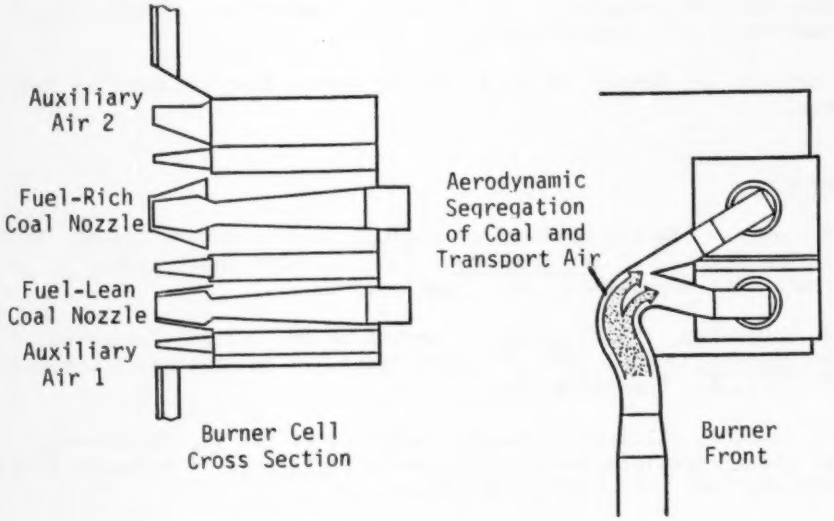
Auxiliary Air 2
Fuel-Rich Coal Nozzle
Fuel-Lean Coal Nozzle
Auxiliary Air 1
Burner Cell Cross Section
Aerodynamic Segregation of Coal and Transport Air
Burner Front

Figure 2. PM Burner System

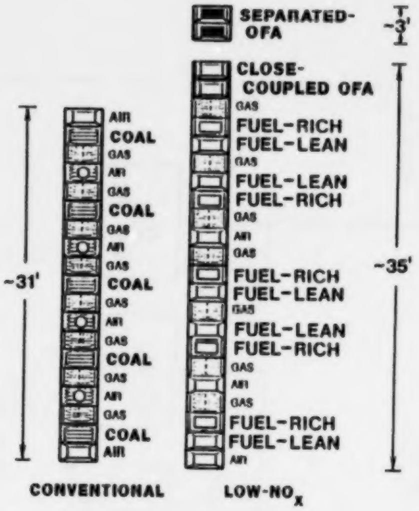
SEPARATED-OFA
~3'
CLOSE-COUPLED OFA
GAS
FUEL-RICH
FUEL-LEAN
GAS
FUEL-LEAN
FUEL-RICH
GAS
AIR
GAS
FUEL-RICH
FUEL-LEAN
GAS
FUEL-LEAN
FUEL-RICH
GAS
AIR
GAS
FUEL-RICH
FUEL-LEAN
AIR
~35'
AIR
COAL
GAS
AIR
GAS
COAL
GAS
AIR
GAS
COAL
GAS
AIR
GAS
COAL
GAS
AIR
GAS
COAL
AIR
~31'
CONVENTIONAL
LOW-NO$_X$

Figure 3. Comparison of Conventional and PM Burner Configurations

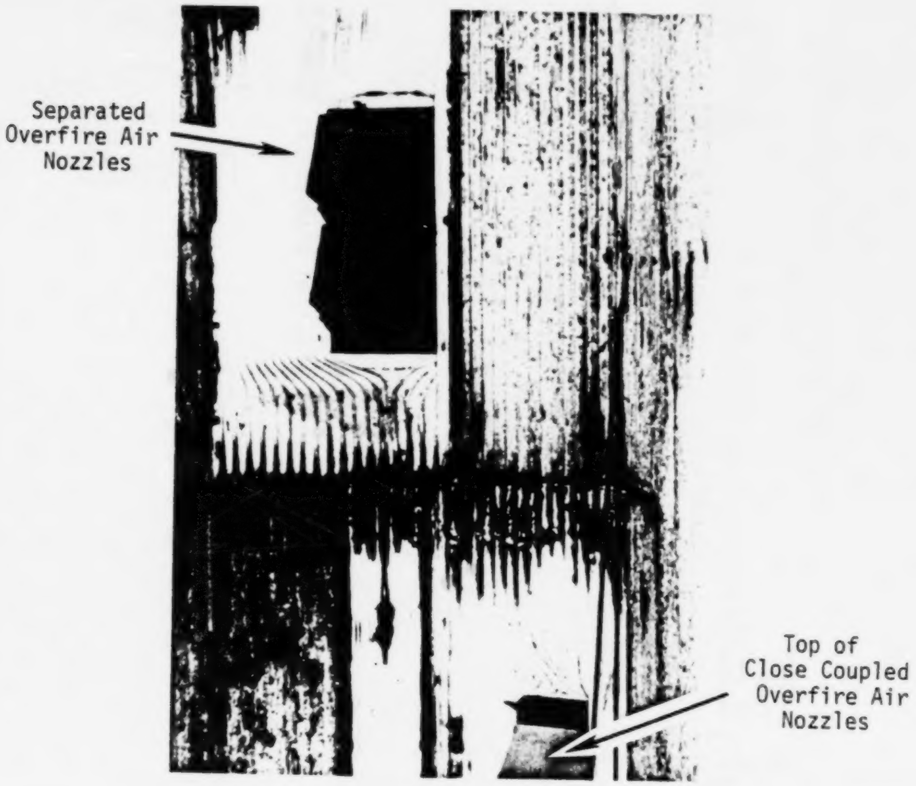
Separated Overfire Air Nozzles
Top of Close Coupled Overfire Air Nozzles

Figure 4. Furnace View of Separated OFA Nozzles (Offset)

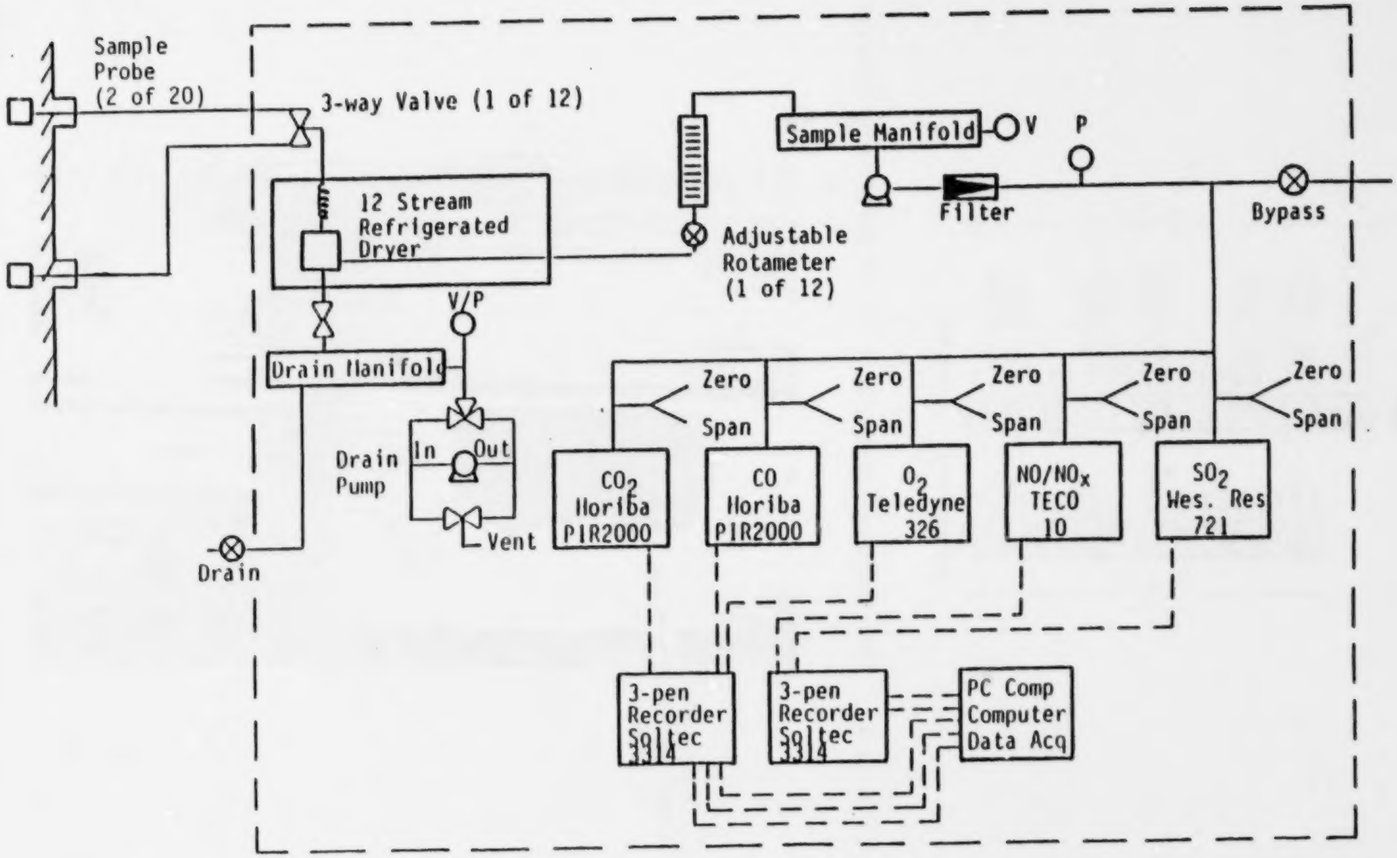
Sample Probe (2 of 20)
3-way Valve (1 of 12)
12 Stream Refrigerated Dryer
Drain Manifold
V/P
In
Out
Drain Pump
Vent
Drain
Adjustable Rotameter (1 of 12)
Sample Manifold
V
P
Filter
Bypass
Zero
Span
Zero
Span
Zero
Span
Zero
Span
Zero
Span
CO_2 Horiba PIR2000
CO Horiba PIR2000
O_2 Teledyne 326
NO/NO_x TECO 10
SO_2 Wes. Res 721
3-pen Recorder Soltec 3314
3-pen Recorder Soltec 3314
PC Comp Computer Data Acq

Figure 5. Flow Schematic of the Continuous Gas Analysis System

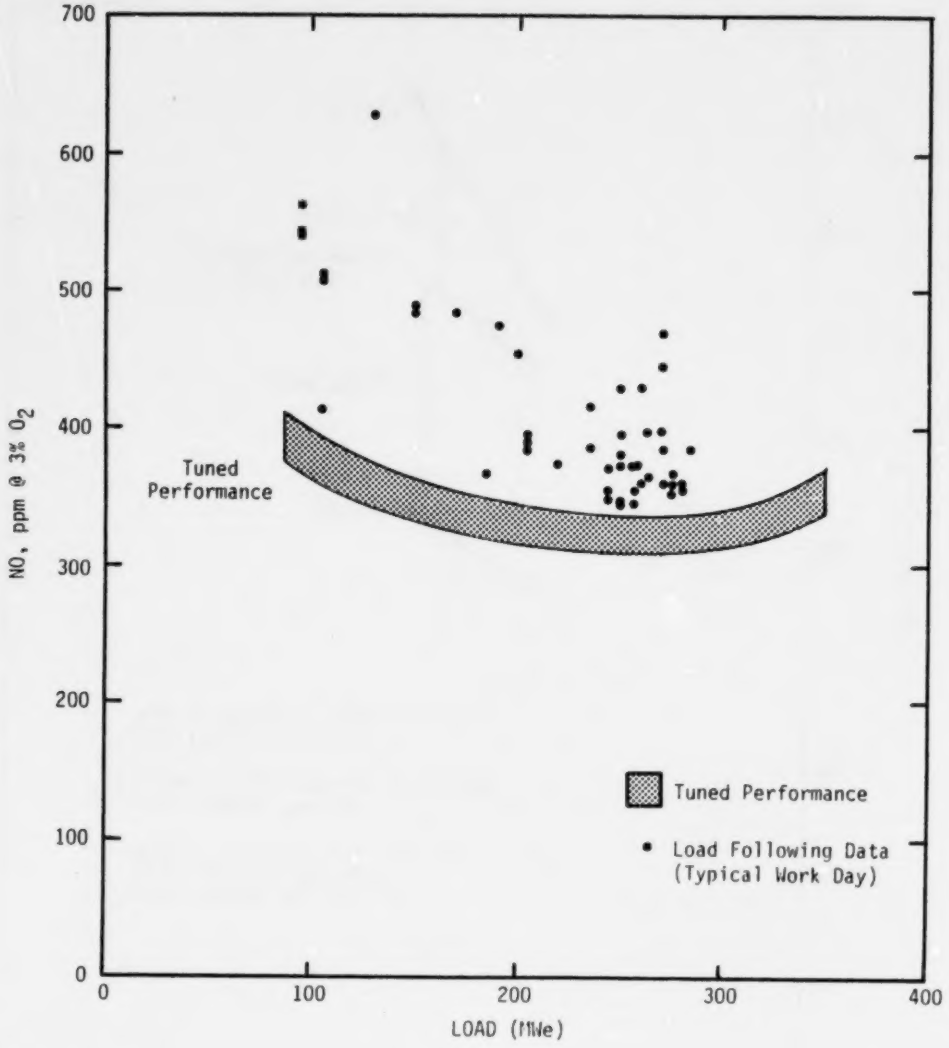

Figure 6. Baseline NO_x Emissions

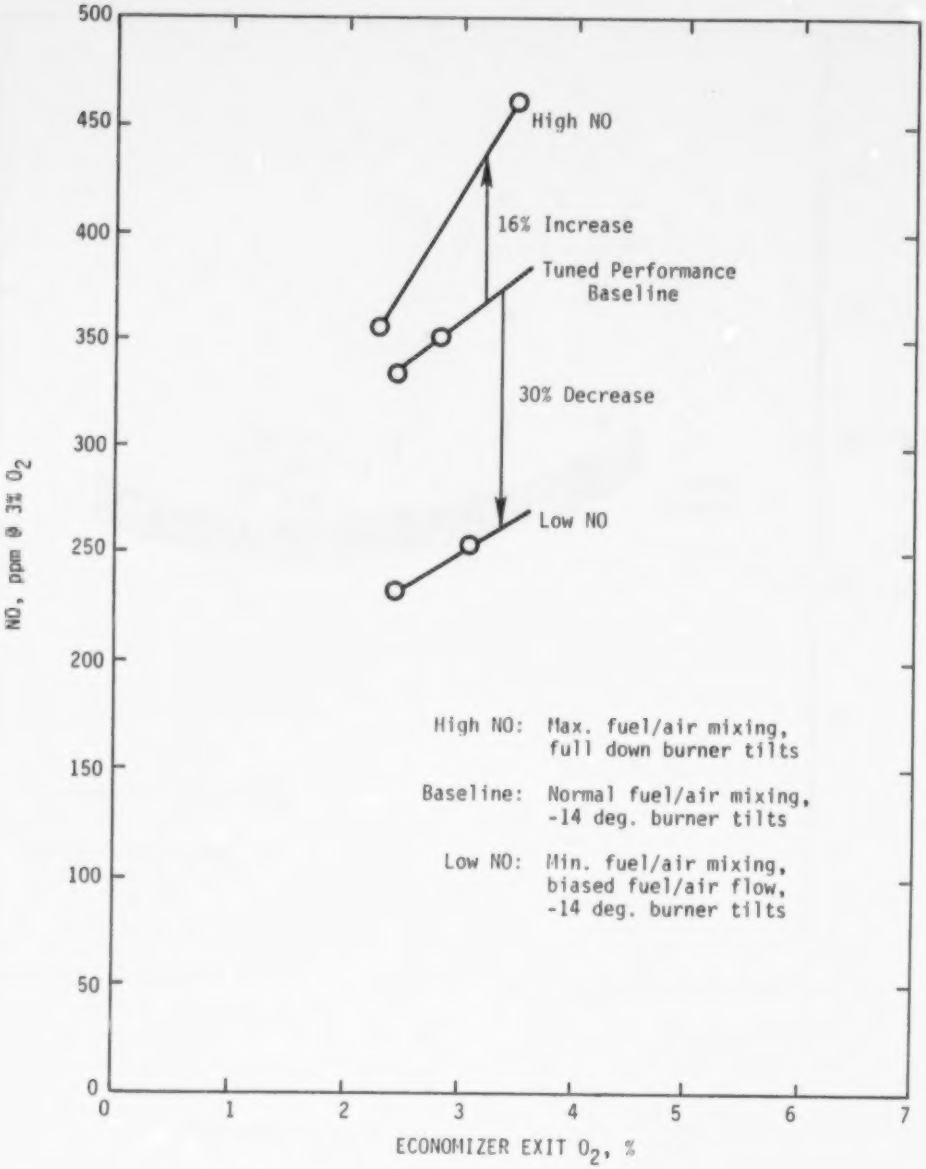

Figure 7. Full Load Baseline NO_x Emissions Variations

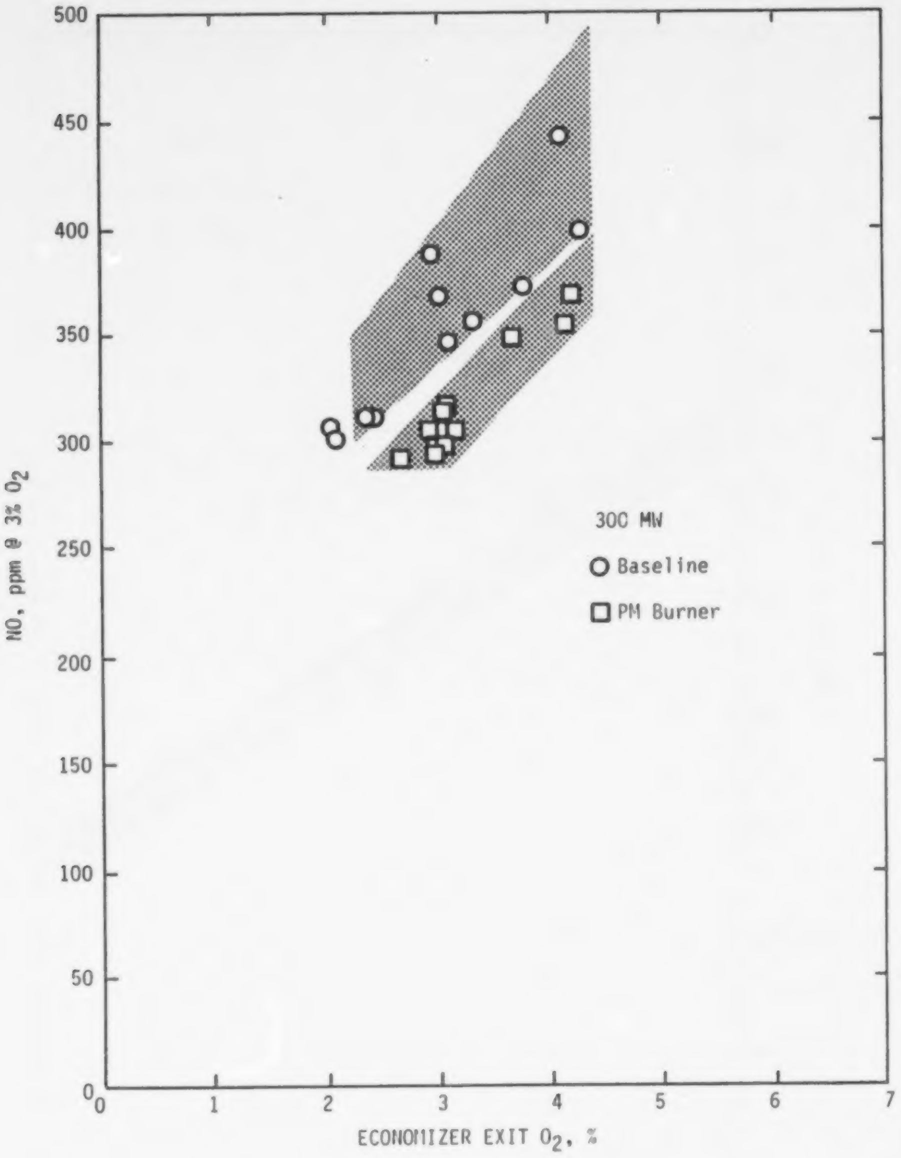

Figure 8. PM Burner NO_x Emissions Without Overfire Air

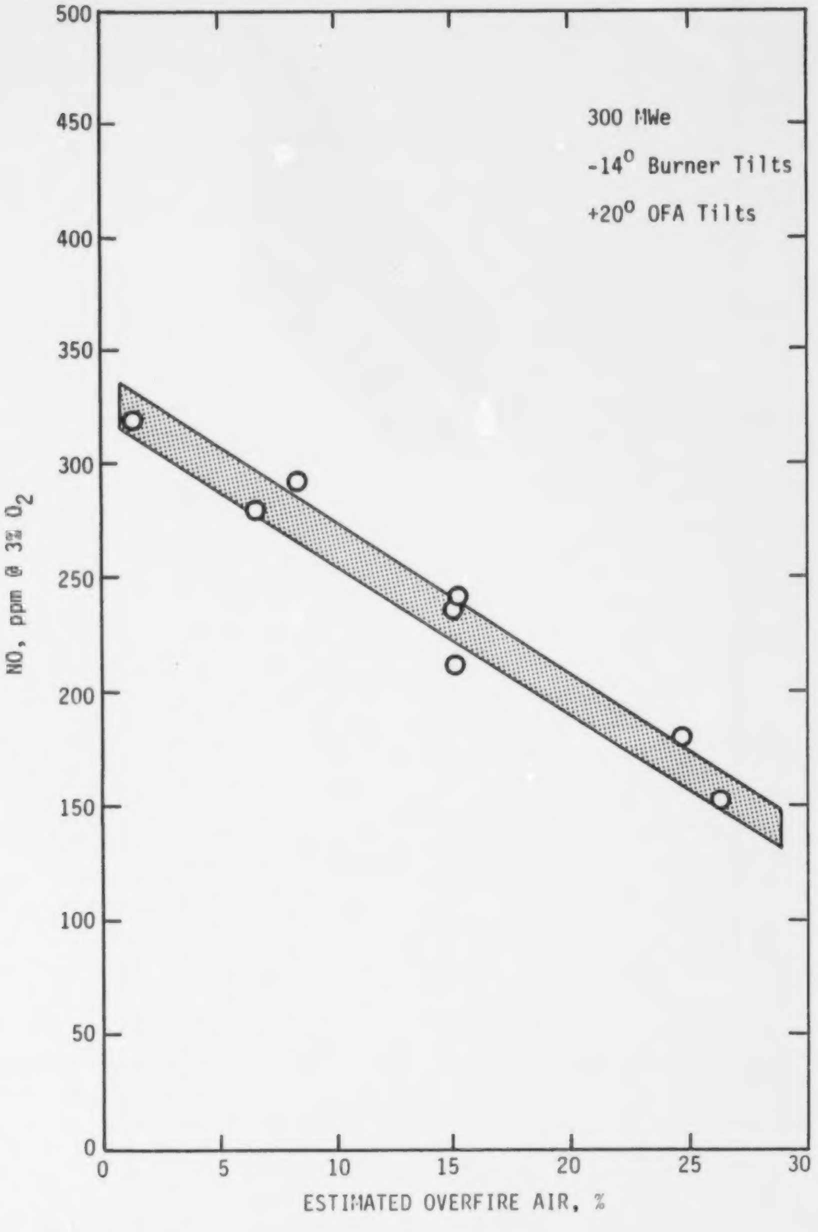

Figure 9. NO_x Dependence on Overfire Air Flow

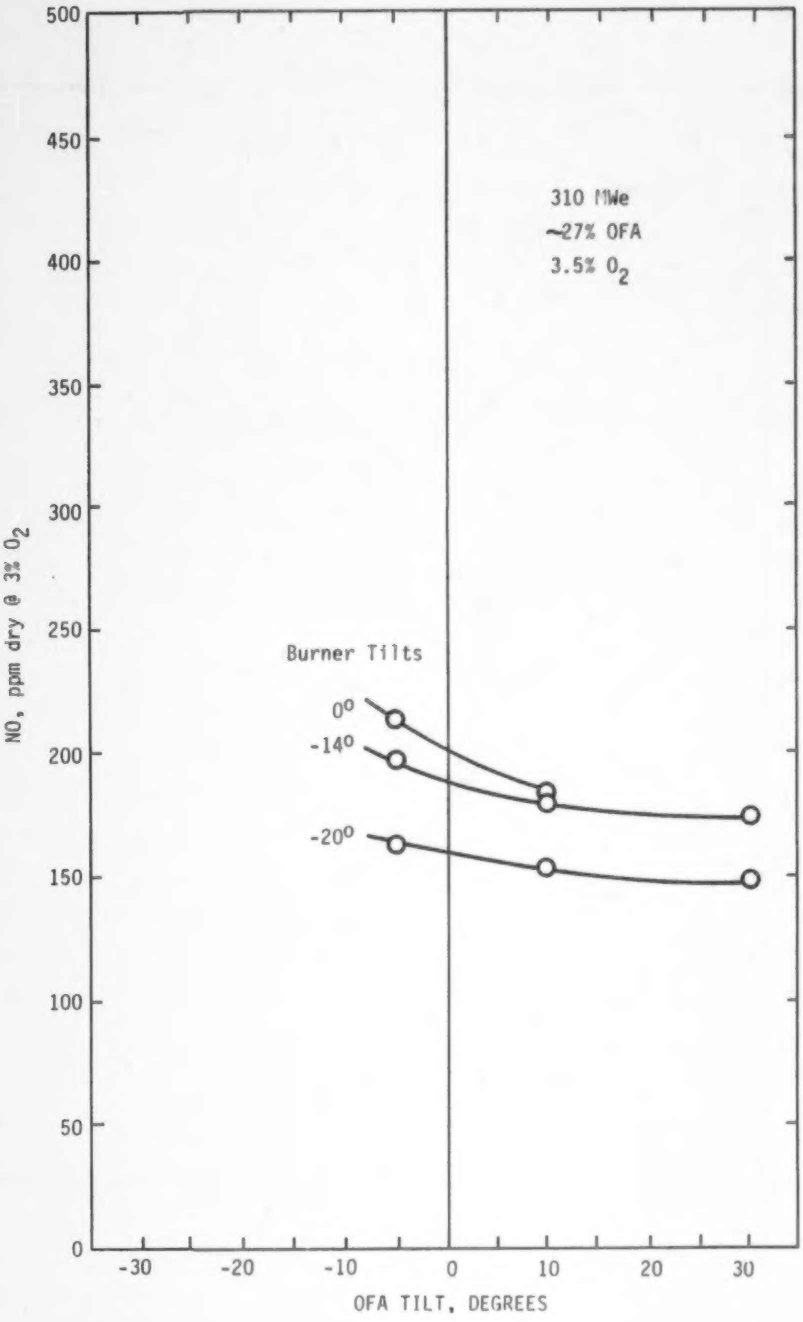

Figure 10. Comparison of NO Dependence on OFA Tilt and for Burner Tilts

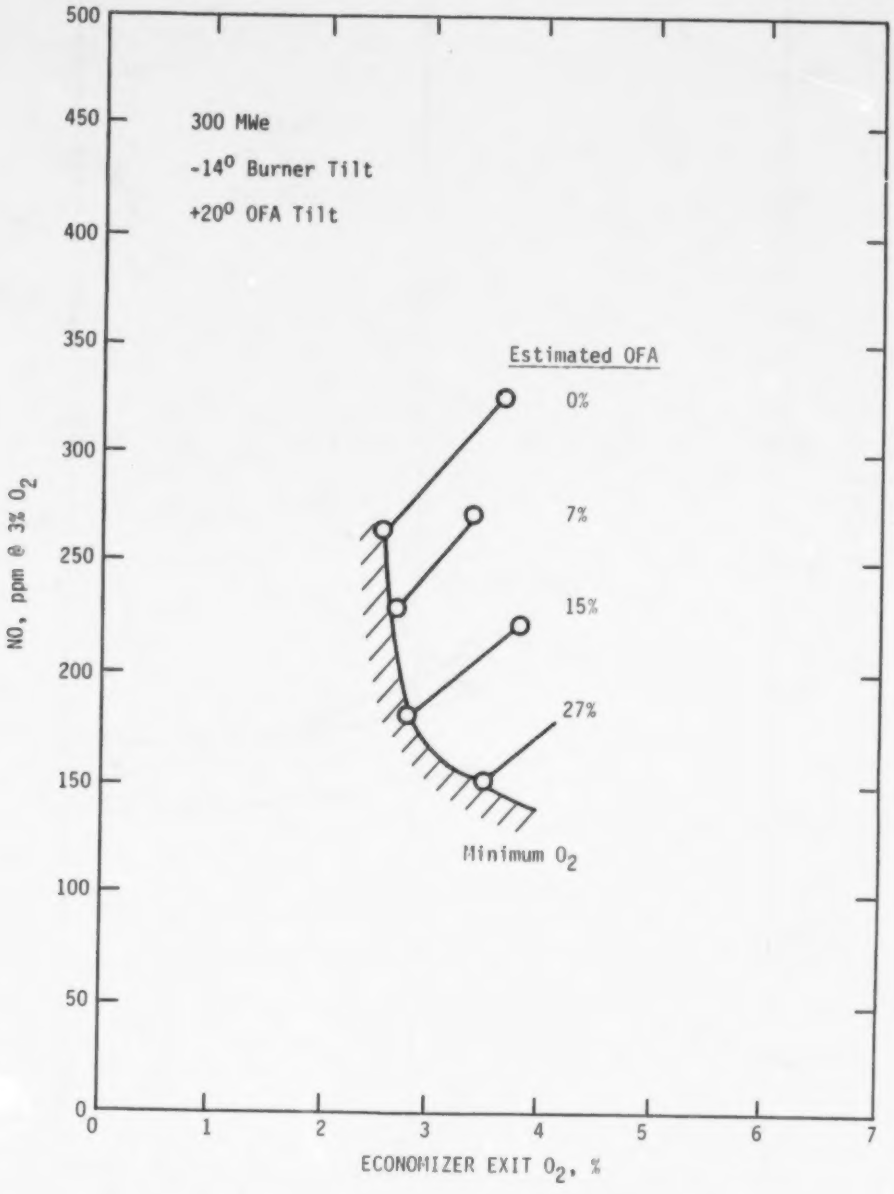

Figure 11. Typical Minimum O_2 vs. OFA Flow Trade-off

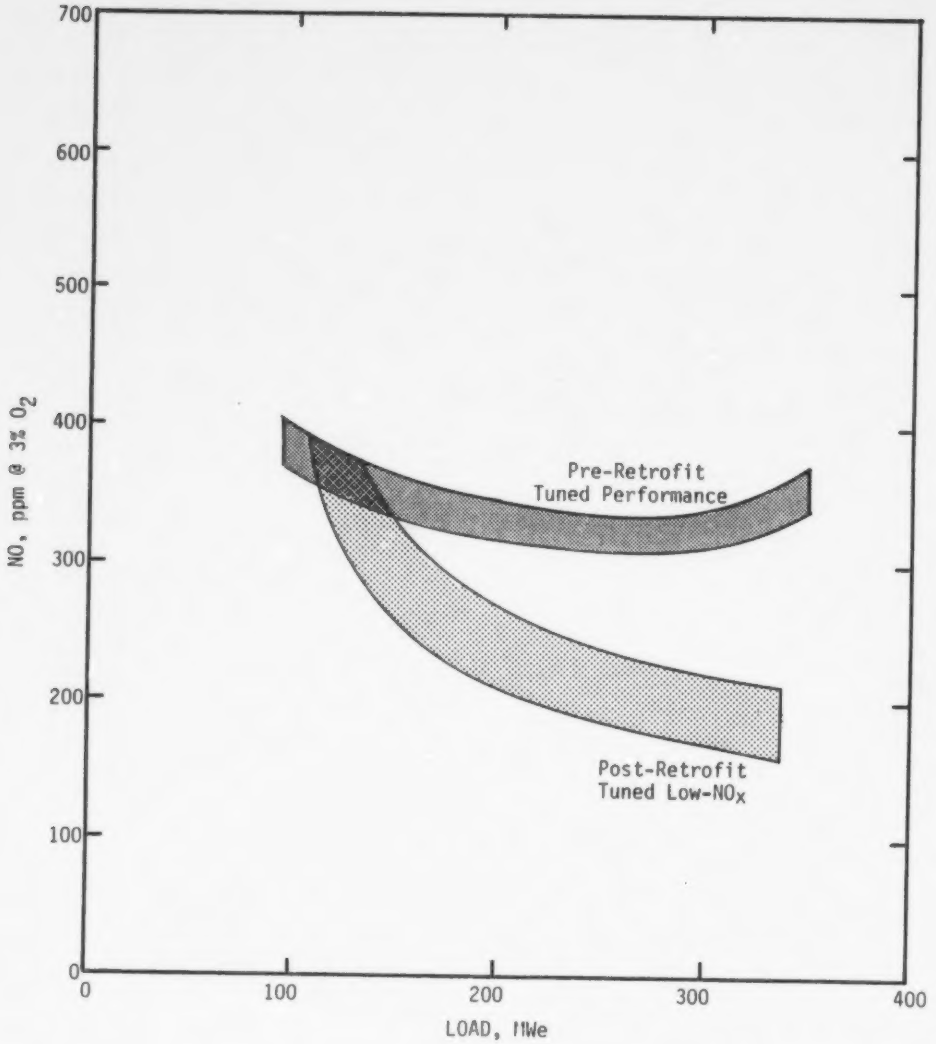

Figure 12. Comparison of Pre- and Post-Retrofit NO_x Emissions Data

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The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

RETROFIT AND BOILER PERFORMANCE EVALUATION OF THE LOW NO_X PM FIRING SYSTEM AT KANSAS POWER & LIGHT

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ABSTRACT

A tangentially-fired boiler, Kansas Power & Light Lawrence Unit #5, was retrofit in July, 1987 by Combustion Engineering with the low NO_x PM Firing System. This retrofit was done as part of a comprehensive EPRI low NO_x combustion demonstration project.

The objective of the test program was to establish the minimum achievable NO_x levels with the low NO_x firing system consistent with no adverse impact on boiler performance or operation. This paper summarizes the effects of the PM firing system on boiler performance and operation.

Results indicate that NO_x emissions reductions of 35% to 50% were achieved with no adverse impacts on boiler operating characteristics such as start-up, minimum load, and flame stability. While changes in boiler thermal performance were measured, these changes have had no significant impacts on power generation. For example, waterwall heat absorbtion was increased which resulted in a decrease in the furnace outlet gas temperature (FOT) of less than 50°F. However, this change in absorbtion (which can affect outlet steam temperature) was easily accommodated via the automated windbox tilt feature integral in the design.

Additionally, at operating conditions promoting the higher achievable NO_x reductions (low emissions), there was a greater tendency to produce higher CO emissions and smoke which was alleviated with higher excess air levels. These higher excess air levels increased dry gas losses, and, as a result, reduced overall boiler efficiency by 0.2-0.3%.

Further testing is planned, beginning in 1989, by EPRI and KP&L to characterize NO_x emissions over an extended time period with the unit operating under normal load dispatch.

INTRODUCTION

EPRI sponsored a comprehensive series of full scale tests of the PM firing system at Kansas Power and Light's (KP&L) Lawrence Energy Center. The test program was comprised of boiler performance and emissions tests. This paper presents a summary of the results from the boiler performance testing conducted by Combustion Engineering as the boiler OEM because of their specialized expertise in this area. Gaseous and particulate emissions tests were completed by an independent contractor, Fossil Energy Research Corporation (FERCO)(1). Combustion Engineering retrofitted the PM firing system at the KP&L Lawrence Unit #5 in the spring of 1987 under a separate contract to KP&L.

BOILER CONFIGURATION

Lawrence Unit #5 is a controlled circulation, radiant-reheat, single cell furnace of balanced draft design. The unit is designed for a maximum continuous rating (MCR) of 2,805,000 Lb/hr of steam flow at a predicted superheat outlet of 1005°F/2620 PSIG and a power output of 400 MWe. At this MCR rating, a reheat inlet flow of 2,450,000 Lb/hr at 638°F/612 PSIG is heated to a predicted reheat outlet of 1005°F. Reheat outlet temperature is controlled by fuel nozzle tilt. Superheat outlet temperature is controlled by desuperheating spray. Pertinent boiler specifications and typical coal analysis are shown in Table 1. A side elevational view of the unit is depicted in Figure 1.

Lawrence Unit #5 was designed in 1967, prior to the implementation of any NO_x regulations. As such, it did not include any NO_x control techniques such as low NO_x burners or overfire air (OFA). There were five coal elevations as well as associated normal auxiliary air and warm-up oil compartments as shown in Figure 2. The unit has a nominal name plate rating of 400 MWe, based on the original design Midwestern bituminous coal which had a higher heating value (HHV) of 12,770 Btu/lb and a Hardgrove grindability of 63. Full load operation was limited to 300-330MWe during these tests due to both the addition of a wet scrubber and a change in coal type fired since the original unit design and construction. The Wyoming Powder River Basin (HHV of 10,750 Btu/lb, Hardgrove grindability of 50) coal currently used limits pulverizer capacity as compared with the original design coal.

The PM firing system retrofit(2) included four (4) completely new windboxes, separated OFA compartments, a new secondary air control system, a partial replacement of the coal piping and larger fan blades on the pulverizer exhauster. The new windboxes, shown in Figure 2, include five elevations of the PM firing nozzles. An elevation of PM firing nozzles includes a fuel rich (Conc) and a fuel lean (Weak) nozzle. Successive elevations of CONC and WEAK fuel nozzle sets have also been inverted (ganged) relative to each other to further emphasize the fuel rich and fuel lean arrangement. The new windboxes also include two elevations of integral or "close coupled" (CC) OFA with vertical tilt capacity. The separated (SEP) OFA includes two individually controlled compartments and has manual vertical and horizontal tilt adjustment capability. Note also, in Figure 2, that the pre-retrofit natural gas firing capability for Unit #5 has been integrated into the PM firing system windbox design. The burner windbox has normal automatic vertical tilt capability used for reheater steam temperature control. The main windbox for the PM firing system is four feet taller to provide for space for the close coupled overfire air. The extra windbox envelope for the PM firing system has been accommodated by stretching the original windbox height while keeping the original windbox centerline constant. The separated overfire air windbox at each corner (4 total) is approximately four feet tall with the bottom of the separated OFA windbox located 6 feet above the top of the close coupled OFA compartment.

The PM firing system at Lawrence #5 was specifically designed for a retrofit application. Changes to existing structural steel members were minimized and the only pressure part changes required were in the furnace waterwalls. A new unit application of the PM firing system would normally increase the vertical centerline spacing between successive fuel elevations to augment the NO_x reduction capabilities of the system. This would require a 25-50% increase(3) in windbox height and thus associated changes in structural members and either an increase in furnace overall furnace height and/or a rearrangement of steam side surfaces. For the Lawrence #5 retrofit the fuel elevation centerline spacing did not change. The extra windbox height was used to accommodate the close coupled OFA which was designed for 10%, or 2/5 of the total overfire air. Retrofits on other units, using this more compact design, may or may not require a windbox extension depending on whether overfire air preexisted, amount of overfire air in the retrofit and existing structural configuration.

New larger fan blades for the pulverizer exhausters were installed both to upgrade the pulverizers (boiler was load limited due to coal quality degradation from design) and to accommodate the increased pressure drop associated with the PM firing system coal pipe elbow separators.

Installation of the PM firing system commenced five weeks prior to the actual outage with the installation of temporary support steel and rigging of hoist lines(4,5). During the outage, a 20 ft. x 20 ft. hole was cut in the right (north) side of the boiler waterwall and a supported rail system was set up through the hole. The existing windboxes were cut free, lowered to the rails and removed from the boiler. The new shop fabricated windboxes were raised to the rails, slid into the boiler and raised into place. The new windboxes, with their associated tube corners, are approximately 40 ft. tall and weigh more than 30 tons apiece. The installation was essentially completed during the allocated 8 week outage. (The actual unit start-up was delayed several weeks to complete a planned turbine overhaul.) Other retrofit activity, which included a new secondary air control system, the separated OFA windboxes and ductwork, the partial coal pipe replacement and the fan blade replacement for the pulverizers was also completed in parallel.

TEST SCOPE

Both pre-retrofit baseline tests and post-retrofit PM characterization tests were conducted. The baseline tests were completed during March and April 1987. The post-retrofit PM characterization tests were conducted during May 1988.

During these test periods parametric studies of the boiler performance were evaluated. Key gaseous emissions data, taken by FERCO are summarized along with boiler performance results. Details of the emission test results are presented elsewhere (1). The boiler performance parameters assessed included:

1. Boiler Thermal and Combustion Efficiency
2. Furnace Outlet Temperature and Distribution
3. Furnace and Convective Steam Sectional Heat Absorptions
4. Steam Temperature Control and Operating Flexibility
5. Air Heater Performance
6. Air and Fuel Flow Distribution
7. Firing System Operation (stability, turndown, etc.)

Tests were conducted to evaluate the effect of the following key operating parameters on the above-mentioned performance parameters:

1. Amount of Overfire Air
2. Overfire Air Location: Separate, Close Coupled, and Combined
3. Fuel Nozzle and Overfire Air Tilt
4. Excess Air Variation
5. Furnace Waterwall Conditions
6. Load

Comprehensive boiler instrumentation was required in order to fully characterize boiler performance. The instrumentation package was mainly comprised of the following:

- Feedwater flow orifice
- Water and steam temperature thermocouples located at the high pressure heater, economizer, superheater sections, and reheat sections (25 total)
- Suction pyrometers (furnace gas temperature)
- Water/steam pressure transducers
- Waterwall chordal thermocouples (36 total)
- Superheater/reheater element thermocouples (68 total)
- Flue gas analyzers (O_2, CO, NO_x) (by FERCO)
- Fuel and ash sampling systems (by FERCO)
- Primary air, secondary air and fuel distribution instrumentation
- C-E Automated Data Acquisition and Reduction System (ADARS)

The computerized ADARS system allowed immediate evaluation of major boiler sectional heat absorption circuits such as the economizer, waterwalls, low temperature horizontal superheater, superheater pendants, and finishing superheater plus the reheat radiant wall and finishing reheat section. The steam cycle flow chart for Lawrence No. 5 is shown in Figure 3.

Unit efficiency was calculated using C-E's standard boiler efficiency software. The heat absorbtion performance and analysis was completed with the aid of C-E's proprietary Reheat Boiler Performance Program (RBPP). This program develops heat balances about the total boiler envelope and about individual heat transfer elements. For this test program the RBPP was run in reverse. That is, acquired field data was input to the program. Using this data and running the program in reverse allowed the furnace outlet temperature to be calculated and sectional heat absorbtion and thermal performance to be evaluated.

The RBPP program is structured in a modular fashion performing the calculations in a predetermined sequence. The calculations begin with the boiler efficiency which is dependent on the fuel analysis, and the general data module which is dependent on the turbine heat balance. The calculations continue as the flue gas flows through the boiler: furnace performance is calculated followed by the convection pass, followed by the air heater. The program's calculation routine is divided into nine (9) modules which are performed in the sequence listed below:

1. Efficiency
2. General Data
3. Mill
4. Net Heat Input
5. Furnace Outlet Temperature
6. Upper Furnace
7. Interface Between Upper Furnace and Steam Generator
8. Steam Generator
9. Air Heater

UNIT CONDITION

Analysis of data from the baseline series of tests showed that, except for a few minor operational problems, the "as found" boiler performance at Lawrence #5 is typical of tangentially fired utility boiler's of that vintage (1967). The operational problems noted included pluggage in a superheater desuperheat spray valve, an air heater gas side outlet temperature imbalance of approximately 100°F at low (200 MWe and below) unit loads, a left to right flue gas O_2 imbalance on the order of 1.5% O_2, and a low fuel distribution at one corner/elevation. These operational issues were taken into account, as best as possible, throughout testing and during data analysis.

An extensive series of baseline tests were conducted. However, since PM performance is best evaluated on a relative basis by comparing post-retrofit results with the baseline, baseline results are discussed below.

TEST CONDITIONS

The following sections review data obtained from parametric testing of the PM firing system; data from the baseline parametric test series is included for comparison.

Parametric tests were carried out at loads ranging between 120 MWe and 330 MWe. The minimum test load was established by the inability to measure turbine steam bypass flow at lower loads.

The maximum test boiler load was set by pulverizer and I.D. fan operating limits.

Excess combustion air was parametrically evaluated over a range between 10% (2% O_2) and 27% (4.5% O_2). Additionally, fuel nozzle tilt variations were tested over their total cycling range (± 25°) and overfire air vertical nozzle tilts therefore were tested between -5° and +20° (from horizontal). Since the PM firing system was designed for operation with both close coupled and separated OFA, OFA location (close coupled and/or separated) was evaluated. Total OFA quantity was also varied from minimum (4% of total combustion air for nozzle cooling only) to greater than 30%.

Additional tests were run to characterize how waterwall cleanliness impacts on boiler performance with the PM system; tests were conducted immediately after waterwall sootblower operation ("clean") and a subsequent test was conducted after ten hours of steady state operation without the sootblowers in service (i.e. representative of "dirty" wall conditions).

EFFECTS ON BOILER THERMAL AND COMBUSTION EFFICIENCY

For deepest NO_x reduction, boiler efficiency with the PM firing system was observed to be 0.2 - 0.3% lower than boiler efficiency with the baseline firing system. The reason for the efficiency change is that a higher than baseline operating excess air level (approximately 0.5 - 1.0% O_2 higher) was required for PM operation at Unit #5. The higher excess air level increases dry gas loss and, as a result, decreases boiler efficiency.

The observation was made throughout the PM tests that in some instances, both CO emissions and smoke emissions increased when the PM system was operated at equivalent to baseline O_2 levels. These observations were, of course, made when comparing both systems at low O_2 levels.

The reason for this increase in O_2 with the PM system is postulated to be a slight increase in the probability and amplitude of O_2 imbalances at the economizer outlet. Both plant O_2 instrumentation and multiple-point O_2 sampling during the parametric trials confirmed the existence and magnitude of the imbalances. Under conditions where the imbalance was significant, local O_2 levels at the economizer outlet would fall below 2%, resulting in increased CO emissions. O_2 imbalances observed on other tangentially-fired boilers are typically on the order of 1-1.5%. Further information on the imbalance is contained in reference 1.

It should be noted that carbon conversion efficiency, as determined via particulate sampling and subsequent chemical analysis, remained essentially constant between the baseline trials and the PM trials. Typically, less than 1.0% carbon-in-fly ash was observed throughout the entire test program. This result is attributed to the fact that the Lawrence #5 coal was a high reactivity Western bituminous with an "as received" volatile matter content of 36-40%. A highly reactive coal is less sensitive to changes in combustion environment (time/temperature history, firing system configuration, etc.) than a less reactive (lower volatile matter) coal. It would be desirable to test less reactive coal types at Lawrence #5 to evaluate the generic applicability of this result.

EFFECT ON FURNACE OUTLET TEMPERATURE AND DISTRIBUTION

Calculated furnace outlet gas temperature (FOT) for normal recommended PM system operation (combined close-coupled/separated OFA) was lower on average (40-60°F) as compared with the baseline firing system FOT. Greater FOT changes (from baseline) were noted when the PM system was operated with separated OFA only (55°-90°F lower FOT on average) or when the PM system was operated with close coupled OFA only (100° - 140°F reduction in FOT).

It should be noted that good correlation was established between measured (suction pyrometry) FOT's and FOT value's calculated using C-E's Reheat Boiler (RHBP) computer code. Since the RHBP generates consistently more accurate FOT information, calculated FOT values were used exclusively in making comparisons between pre- and post- PM retrofit FOT's.

Calculated FOT's for a number of test cases are presented in Figure's 4, 5A, 5B, and 5C. Figure 4 presents calculated furnace outlet gas temperatures in the baseline case, vs. furnace NHI, or net heat input. NHI, in boiler practice (which roughly correlates with load) describes the heat available to the furnace from the higher heating value of the fuel corrected by subtracting radiation losses, unburned combustible, latent heat of water in the fuel, and adding sensible heat in the air for combustion. PM, under normal operation (with separated and close coupled OFA) has an indicated FOT reduction of 40°-60°F on average from baseline, as shown in Figure 5A. PM, with separated OFA only (Figure 5B) shows a 60°-90°F reduction and finally, PM with close coupled OFA only (Figure 5C) shows a 100°-140°F reduction.

The above result is consistent with firing system tilt observations made during testing. With the tilts automatically providing steam temperature control, the baseline firing system fuel nozzle tilts ranged between -10° to -15°F from horizontal, while for the PM firing system the fuel nozzle tilts automatically ranged between -5° to -10°, which, all other factors considered equal, would equate to the PM tilt system compensating for lower average FOT's compared to baseline.

Figure 6, which shows typical predicted waterwall heat absorbtion and furnace outlet temperature versus windbox stoichiometry, provides a basis for understanding a reduction in FOT with PM. Windbox stoichiometry in Figure 6, is defined as total furnace stoichiometry with excess air minus overfire air. (For example 25% OFA with 15% excess air yields 1.15 - (0.25) (1.15) = 0.86 windbox stoichiometry.) As the windbox stoichiometry decreases towards 1.0, there is less gas dilution which yields higher flame temperatures and increased waterwall heat absorbtion subsequently lowering FOT. As the windbox stoichiometry decreases below 1.0, the combustion process is delayed which lowers flame temperatures and combustion occurs higher in the furnace which yields decreased waterwall absorbtion and an increase in FOT.

The baseline windbox stoichiometry was approximately 1.15; PM with combined overfire air windbox stoichiometry was approximately 0.85; and PM windbox stoichiometry with either close coupled or separated overfire air alone was approximately 0.95.

Based on the above analysis, operations which yield a windbox stoichiometry close to 1.0 should result in the lowest FOT and highest waterwall absorbtion. This is borne out in practice as PM operation with either close-coupled or separated OFA (stoichiometry ~0.95) had relatively large FOT reductions (60°-145°F) on average as compared with PM with combined OFA (stoichiometry ~0.85, 40°- 60°F reductions on average).

It should be noted that, since the FOT calculations are site specific to Lawrence Unit #5, one should not assume that the absolute values of the above cited FOT's will be generally applicable to the T-fired boiler population at large. The above results, however, do reinforce the need to review retrofit PM system impact on FOT on a case-by-case basis.

In addition to the above, test data was obtained to quantify point-to-point furnace outlet gas temperature distributions under pre- and post PM retrofit conditions. Figure's 7A and 7B present typical examples of data from both the baseline and PM firing system parametric tests. The results show generally uniform gas temperature profiles with a peak-to-peak differential typically less than 200°F left-to-right and/or front-to-rear. The gas temperature profiles are slightly more uniform in the baseline case than the PM case, however, the magnitude of the change noted with PM operation was insignificant and will not have any negative impact on normal furnace operation.

BOILER SECTIONAL HEAT ABSORBTIONS

Figure 8 presents typical waterwall and economizer sectional heat absorbtions for the baseline tests and several PM firing system configurations including: 1) PM without OFA; 2) PM with close coupled OFA only; 3) PM with separated OFA only; and 4) PM normal operation. With the as-found baseline configuration the furnace waterwalls absorbed 39% of the total unit heat absorbtion. The waterwall absorbtion (radiative) increased with the PM firing system retrofit with a maximum waterwall absorbtion of 44% observed with both the close coupled OFA only and separated OFA only PM configurations. With the normal PM configuration (combined OFA) the waterwall absorbtion was more in line with the baseline level at 40% (a 1% increase over baseline). These actual results are consistent with changes in FOT presented in Figure 5A, 5B, and 5C and explanation given earlier (Fig. 4). The changes in economizer (convection) absorbtions, as shown in Figure 8, are inversely proportional to the changes in waterwall absorbtion. Thus, if more heat is absorbed in the waterwalls, less heat is available for the economizer.

Other steam sections were also instrumented and changes were monitored and shown in Figure 8. These other sections include the LT superheat, SH division panel, SH platen, HT SH pendant, RH radiant, and HT RH pendant sections.

It should be noted that, in general, for both baseline and PM, increased excess air resulted in decreased waterwall absorbtion as the furnace gas temperatures were decreased by dilution as would be expected. Also, increased furnace waterwall slagging resulted in decreased furnace absorbtion, again as expected.

STEAM TEMPERATURE CONTROL

Full load steam temperature control has also not changed except for the nominal fuel nozzle tilt position previously discussed. Waterwall cleanliness and rate of slag accumulation remained essentially unchanged. The variation in FOT due to slag accumulation was approximately 100°F (equivalent to 3% change in waterwall heat absorbtion) for both firing systems. This 100°F change in FOT due to slag variations is not unusual; 300-400°F changes have been observed on units with thick slag accumulations.

EFFECTS ON LOAD, START-UP, ETC.

Flame stability, boiler start-up and shut down procedures, load ramp rate and load following operation after PM retrofit were identical to pre-retrofit baseline operation.

Minimum achievable boiler load was unaffected by the installation of the PM system; the unit is capable of operating at 15%-20% of the design maximum continuous rating (MCR) of 400 MWe.

AIR AND FUEL FLOW DISTRIBUTION

Figures 9A & B present the primary air velocity and fuel massflow distribution for the PM firing system upstream of the elbow separator. Both the fuel and air corner-to-corner distributions on all five fuel elevations are within normal design tolerances (± 5% tolerance for each corner for both air and fuel splits). The baseline tests provided similar results with only one elevation/one corner providing a fuel distribution out of specification. This flow imbalance was corrected during the PM installation outage. The primary air flow was approximately 12% higher with the PM system due to the pulverizer exhauster fan blade retrofit.

The PM elbow separator performance is shown on Figures 10A & B. These fuel and air splits shown are as per design with an approximately even air velocity split and a fuel mass flow split of 80/20 for the CONC and WEAK nozzles, respectively. Additionally, it should be noted that the coarser coal particles favored the CONC nozzle (53% minus 200 mesh and 1.5% plus 50 mesh) rather than the WEAK nozzle (94% minus 200 mesh and 0% plus 50 mesh); this result is not unexpected with the elbow separator design.

The pressure loss associated with the installation of the PM elbow separator was determined to be less than 1.0 inch W.G.

Testing indicated that operating with balanced dampers on the windbox fuel and air compartments and at a slightly higher than baseline windbox pressure (approximately 1.0 inch W.G. higher) yielded an improvement in the occasional backpass O_2 imbalance.

TYPICAL EXCESS AIR LEVEL

With the PM firing system the typical O_2 values range between 3.0-3.5%, depending on OFA quantity. This compares with pre-retrofit baseline typical O_2 values of 2.5 - 2.7%. This increase in excess oxygen is due to an increased propensity for an O_2 imbalance to occur with PM. This is especially true for operations yielding the highest NO_x reductions (i.e. with significant quantities of OFA, particularly separated OFA, high tilt differential between the fuel and OFA nozzles.

NO_x EMISSIONS

Nominal baseline results were approximately 350-400 ppm (all NO_x values corrected to 3% O_2). Typical PM firing system NO_x values were approximately 180 - 225 ppm @ 3% O_2 and 20% total OFA. Typical PM firing system NO_x values were approximately 150-180 ppm @ 3% O_2 and 25% total OFA. Approximately 70% of this reduction can be attributed, based on comparative tests conducted, to overfire air while approximately 30% was due to the PM windbox modification.

A detailed summary of NO_x emissions from this program is contained in reference 1.

Combustion Engineering is currently working with EPRI, KP&L, and FERCO in order to establish recommendations for long term boiler operation. These recommendations will be integrated into the six month duration emission's monitoring period planned for the unit in 1989.

REPORT CONCLUSIONS

The following summarizes key findings reviewed in this report:

- A low NO_x PM firing system appears to be a viable retrofit option for many existing T-fired boilers. An economic/application study is planned by EPRI to quantify this issue.

- The retrofit system achieved NO_x reductions on the order of 35 - 50% (from a baseline level of 350 - 400ppm) at full load under tuned short-term test conditions.

- At maximum NO_x reduction operation operating excess air level's increased as a result of the PM retrofit (~0.5. to 1.0% O_2 increase); overall boiler efficiency was reduced slightly (0.2% - 0.3%) after PM retrofit as a result of the additional required excess air when operated at very low NO_x levels.

- Waterwall heat absorbtion increased slightly (less than 1%) after PM retrofit when the PM system was operated as recommended (using combined close-coupled and separated OFA); a change in fuel nozzle vertical tilt (+5° towards horizontal) accommodated this change.

- Furnace outlet temperature (FOT) after PM retrofit under recommended operating conditions was 40° - 60°F lower on average than baseline pre-retrofit FOT.

- Waterwall cleanliness and rate of slag accumulation was unchanged as a result of the PM installation.

- Carbon in fly ash levels were less than 1%, both pre and post PM retrofit, for the reactive coal tested.

- The PM system had no adverse affects on boiler start-up, minimum load, or flame stability.

ACKNOWLEDGEMENTS

First and foremost we would like to acknowledge Mr. P. Tempero, Plant Manager, and the operating and engineering staff at Kansas Power & Light's Lawrence Energy Center. Their commitment to and assistance throughout the program was a tremendous benefit.

We would also like to acknowledge the Fossil Energy Research Co. and Energy Systems Associates staff who put in many long days during the testing. This acknowledgement also applies to the Combustion Engineering Technical Services staff involved with the program.

We would also like to acknowledge the many C-E and KP&L people that were involved in the system design and retrofit.

This project was funded, in part, by the Kansas Electric Utility Research Program.

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1. Thompson, R., et al, NO_x Emissions Reduction for a 350 MW Low NO_x PM Burner Retrofit, Proceedings: 1989 EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, San Francisco, CA.

2. McCartney, M.S., et al, 1987 Update on NO_x Emissions Control Technologies at Combustion Engineering, Proceedings: 1987 EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, New Orleans, LA.

3. Kokkinos, A., et al, Part I: Feasibility Study of a Low NO_x Retrofitable Firing System with U.S. Coals, Proceedings: 1982 EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, Dallas, TX.

4. Tempero, P., Installation and Operation of Low NO_x PM Burners, Presented at the Fifty-ninth Annual Engineering Conference of Missouri Valley Electric Association, Kansas City, MO, March 1988.

5. Kuether, R.C., et al, Cut NO_x with New Burner System, 1988 Electric Utility Planbook.

TABLE 1
KANSAS POWER & LIGHT COMPANY
LAWRENCE UNIT NO. 5

GENERATOR RATING	400 MWe
MAXIMUM STEAM FLOW	2,805,000 lb/hr
SUPERHEAT STEAM TEMPERATURE/PRESSURE	1005°F/2620 psig
FURNACE WIDTH	50' - 8''
FURNACE DEPTH	40' 2-1/8''
FIRING SYSTEM	TILTING TANGENTIAL
PULVERIZERS	FIVE 743RS (WITH EXHAUSTERS)

Typical FUEL ANALYSIS:	(As Recieved)
MOISTURE	10.5 %
VOLATILE MATTER	38.0 %
FIXED CARBON	42.9 %
ASH	8.6 %
H	4.50%
C	61.91%
S	0.47%
N	1.27%
O	12.75%
ASH	8.60%
MOISTURE	10.50%
HHV	10,884 Btu/lb

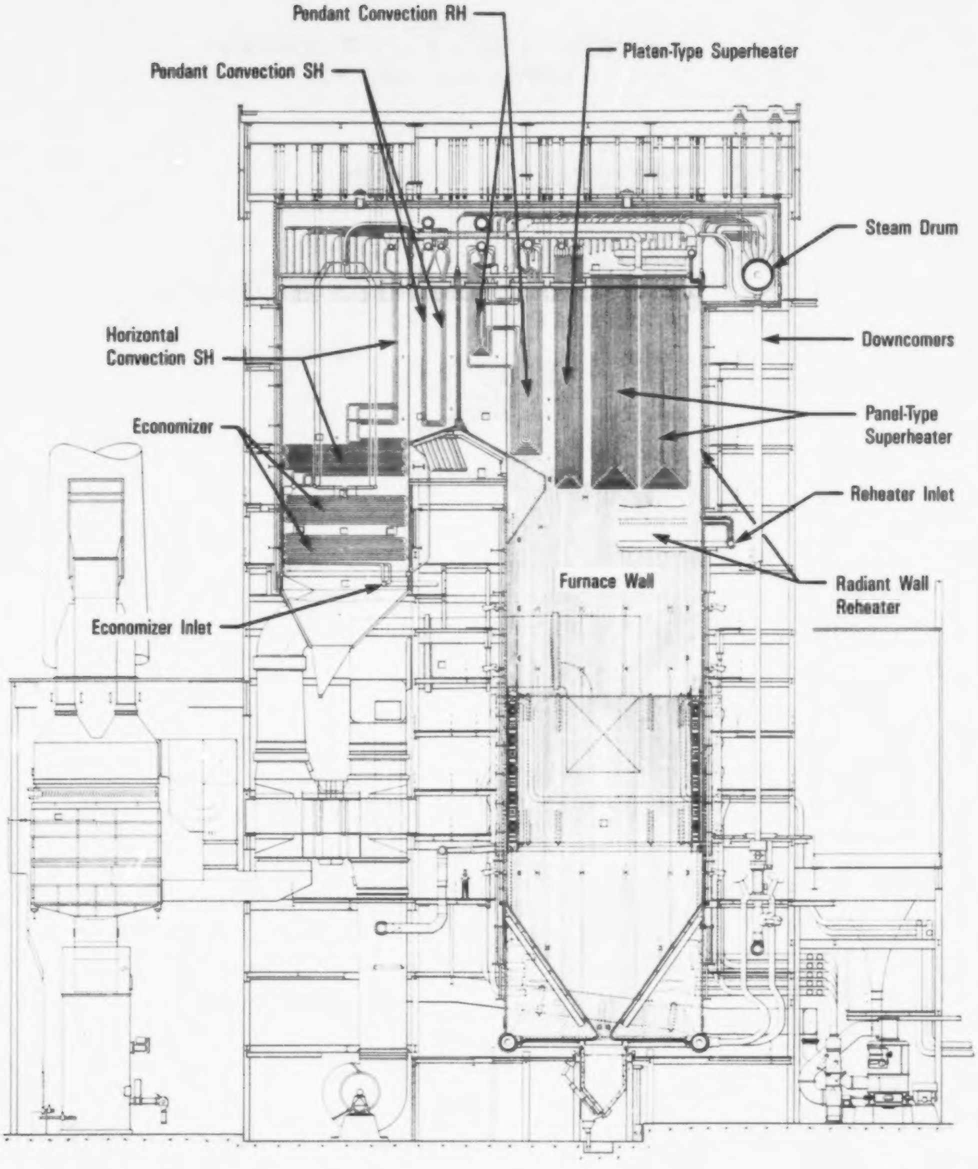

Pendant Convection RH
Pendant Convection SH
Platen-Type Superheater
Steam Drum
Horizontal Convection SH
Downcomers
Economizer
Panel-Type Superheater
Reheater Inlet
Furnace Wall
Radiant Wall Reheater
Economizer Inlet

Figure 1: Side Elevation of Kansas Power & Light Gas Services Lawrence Energy Center Unit No. 5 as Originally Built

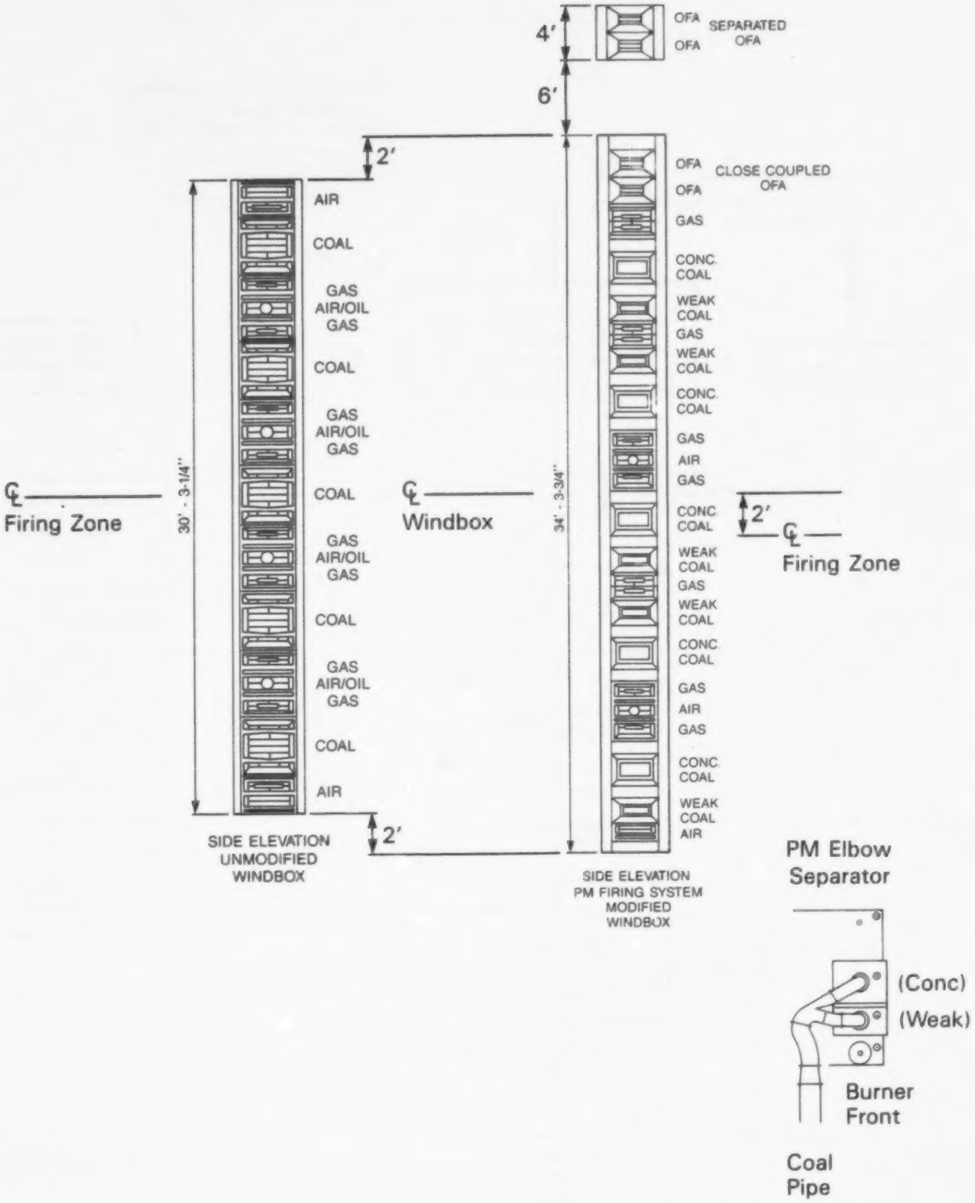

4'
OFA
OFA
SEPARATED OFA
6'
2'
OFA
OFA
CLOSE COUPLED OFA
GAS
CONC. COAL
WEAK COAL
GAS
WEAK COAL
CONC. COAL
GAS
AIR
GAS
CONC. COAL
WEAK COAL
GAS
WEAK COAL
CONC. COAL
GAS
AIR
GAS
CONC. COAL
WEAK COAL
AIR
34' - 3-3/4"
2'
℄ Firing Zone
℄ Windbox
AIR
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
AIR
30' - 3-1/4"
℄ Firing Zone
2'
2'
SIDE ELEVATION UNMODIFIED WINDBOX
SIDE ELEVATION PM FIRING SYSTEM MODIFIED WINDBOX
PM Elbow Separator
(Conc)
(Weak)
Burner Front
Coal Pipe

Figure 2: Schematics of Unmodified & PM Modified Windboxes at Kansas Power & Light Lawrence Unit No. 5

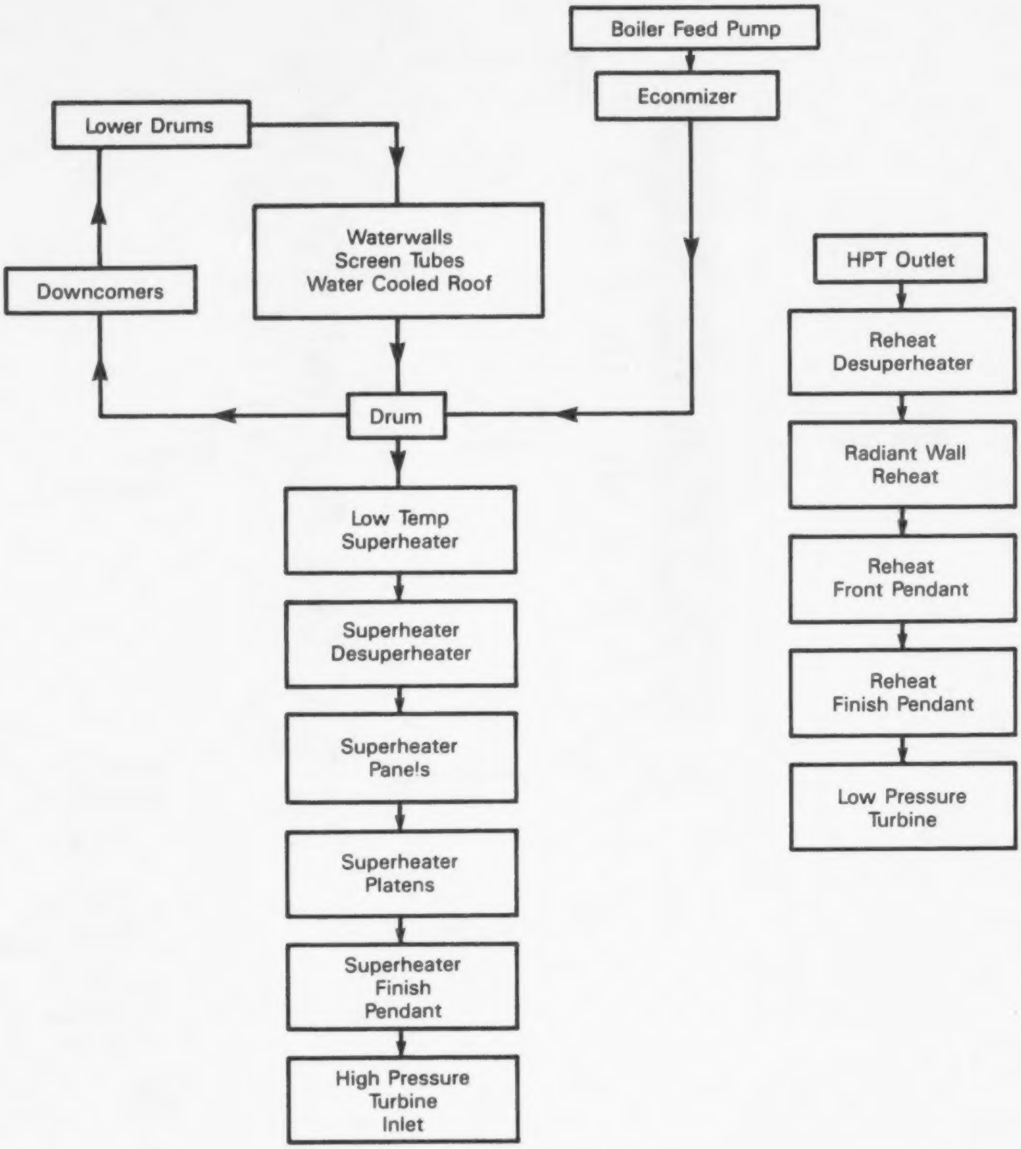

Boiler Feed Pump
Econmizer
Lower Drums
Waterwalls
Screen Tubes
Water Cooled Roof
Downcomers
Drum
HPT Outlet
Reheat
Desuperheater
Radiant Wall
Reheat
Reheat
Front Pendant
Reheat
Finish Pendant
Low Pressure
Turbine
Low Temp
Superheater
Superheater
Desuperheater
Superheater
Panels
Superheater
Platens
Superheater
Finish
Pendant
High Pressure
Turbine
Inlet

Figure 3: Water & Steam Cycle at Kansas Power & Light Lawrence No. 5

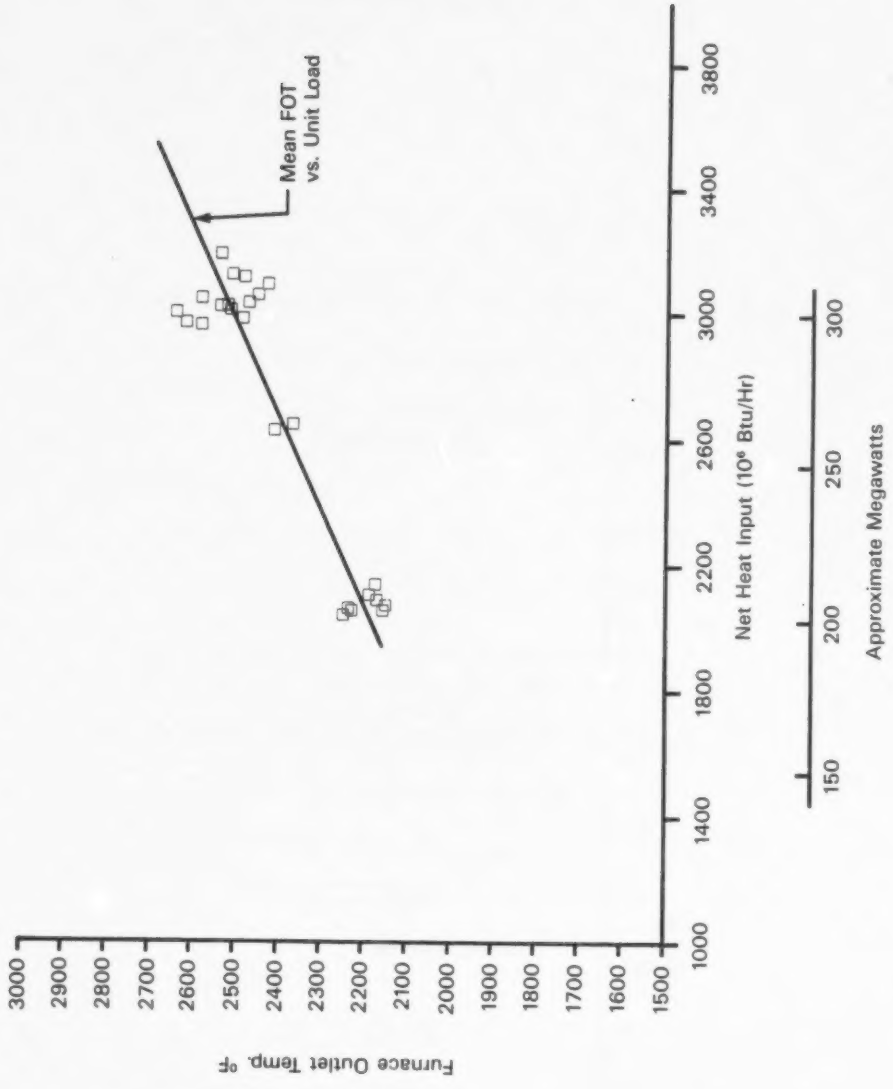
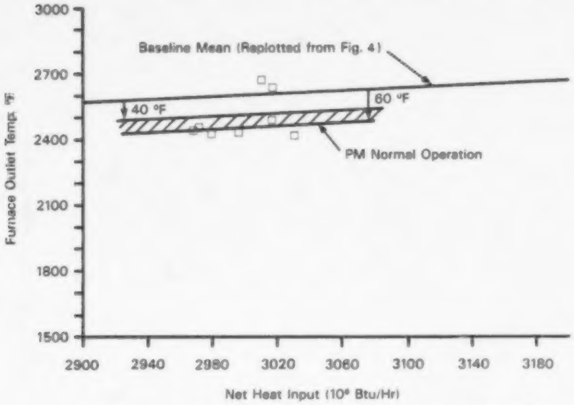
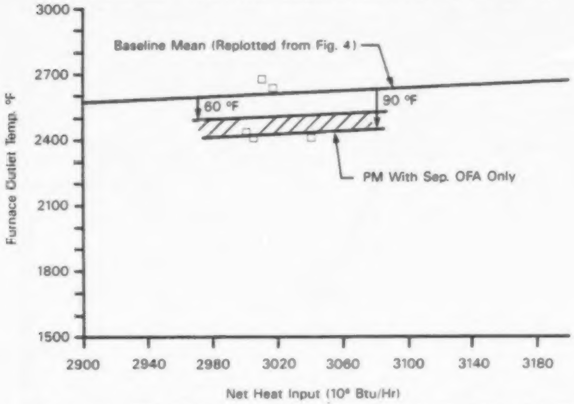


Figure 4: Baseline Furnace Gas Outlet Temperature vs. Unit Load

A. PM Full Load - Normal Component Overfire Air Operation



B. Full Load - PM With Separated Overfire Air Only



C. Full Load - PM Firing With Close Coupled Overfire Air Only

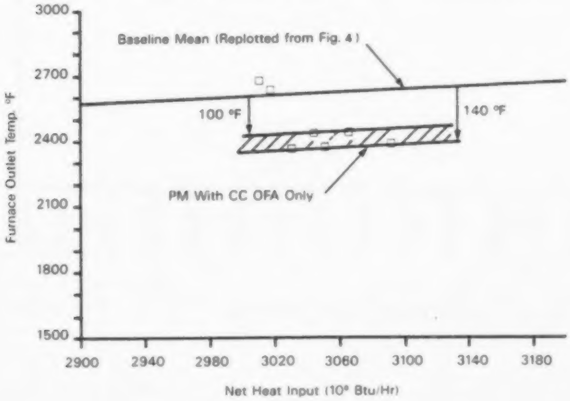


Figure 5: Comparison of Baseline Calculated Furnace Outlet Temperature to the FOT with PM with Different Overfire Air Configurations

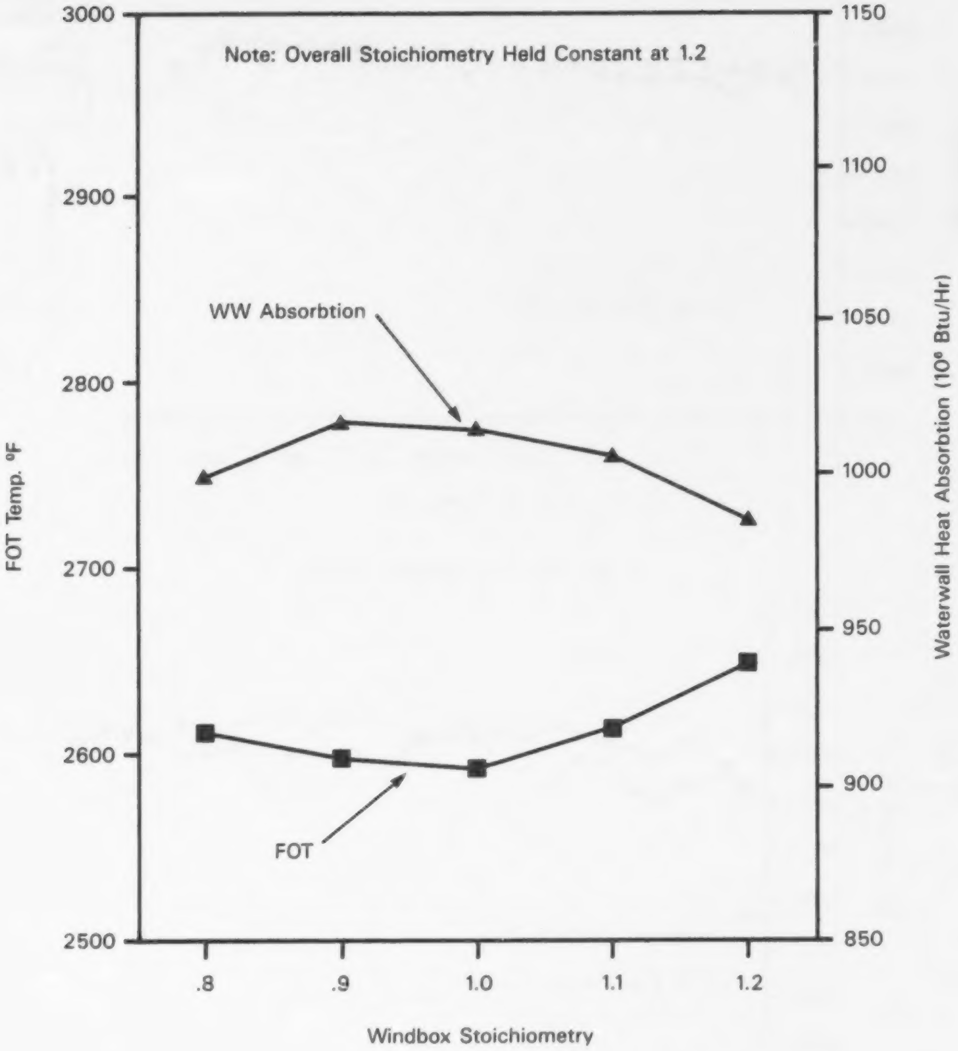
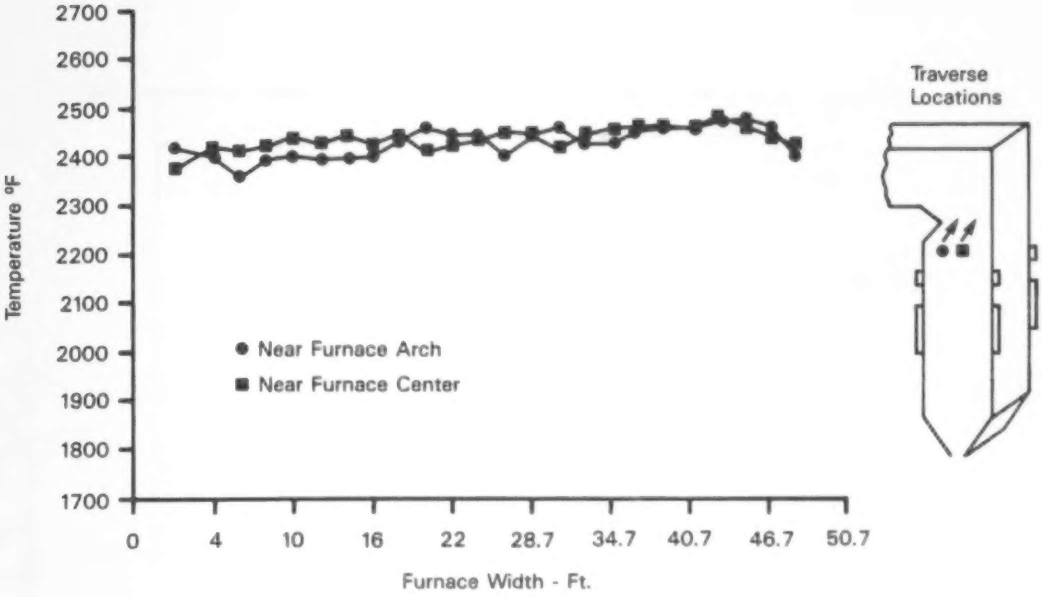


Figure 6: Predicted Furnace Outlet Temp. & Absorbtions vs. Windbox Stoichiometry

A. Baseline Traverse



B. PM Firing System Traverse

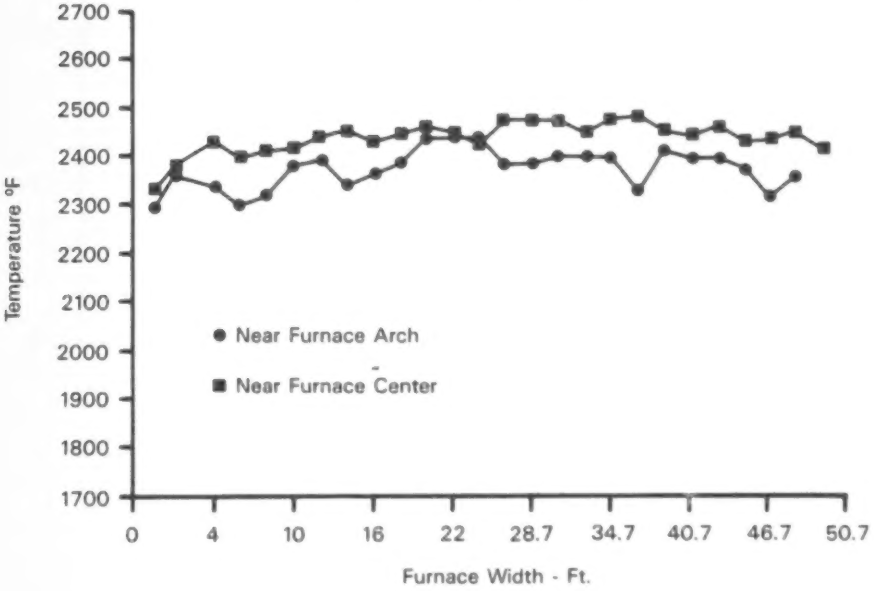


Figure 7: Typical Baseline and PM System Furnace Outlet Suction Pyrometer Traverses

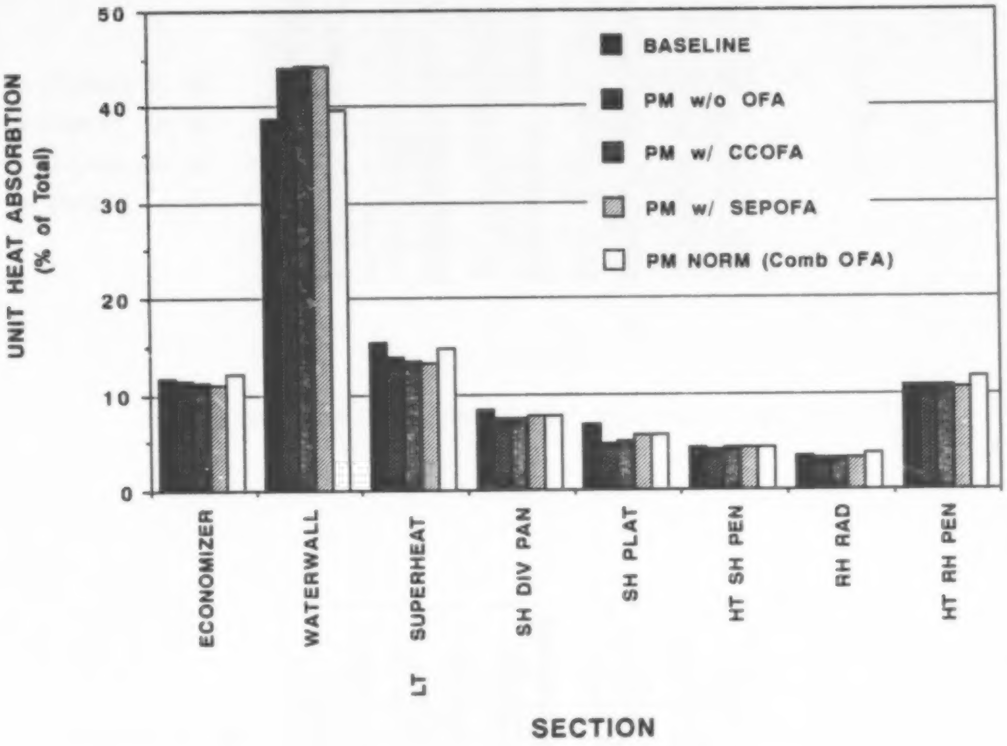
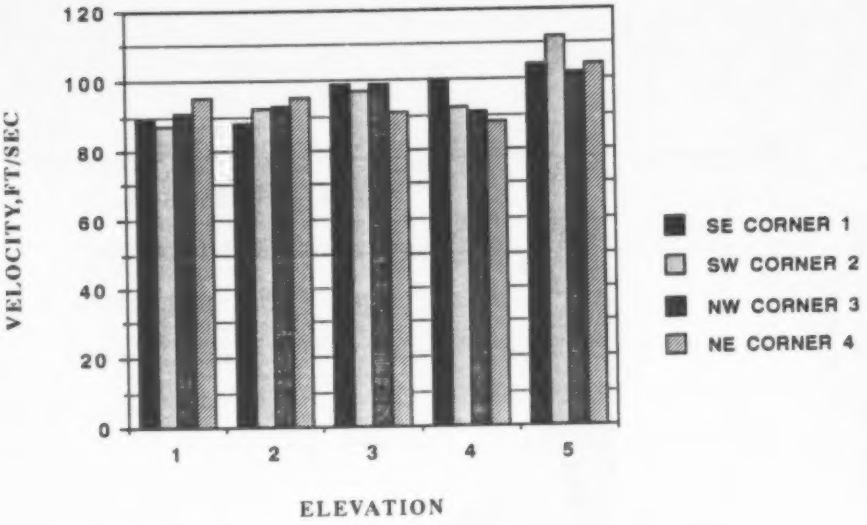
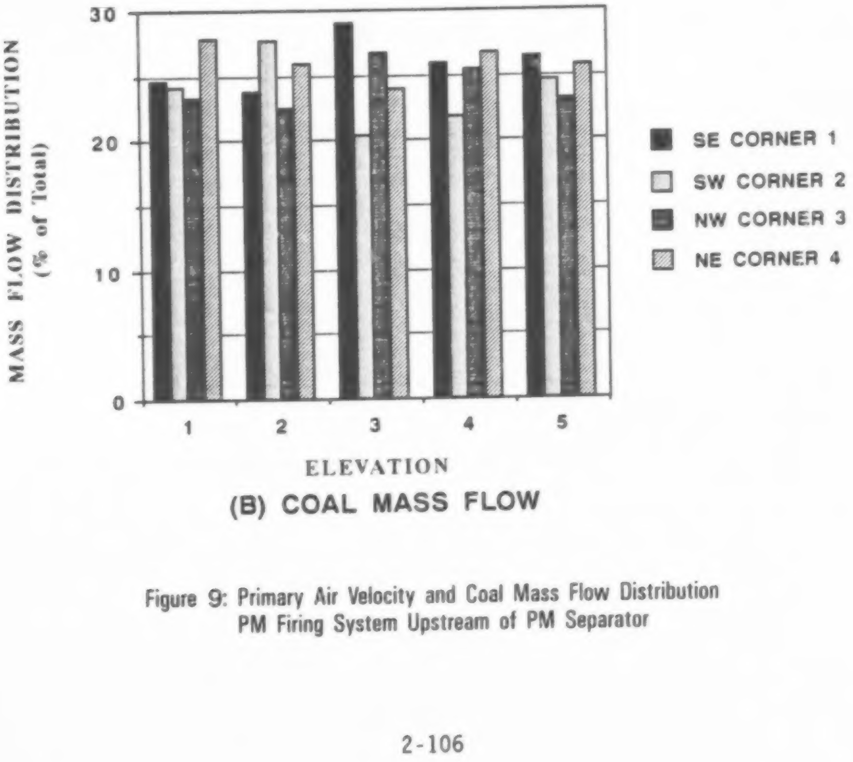


Figure 8: Sectional Heat Absorbtion Summary

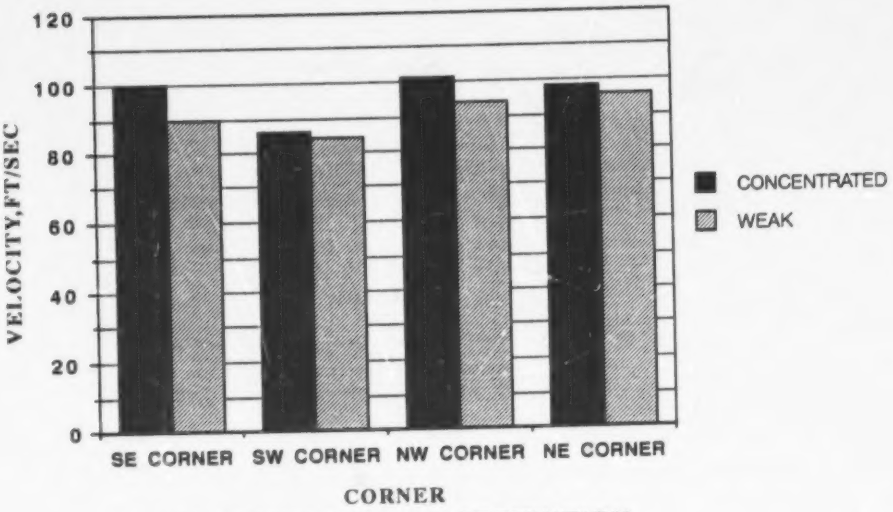


(A) PRIMARY AIR VELOCITY DISTRIBUTION

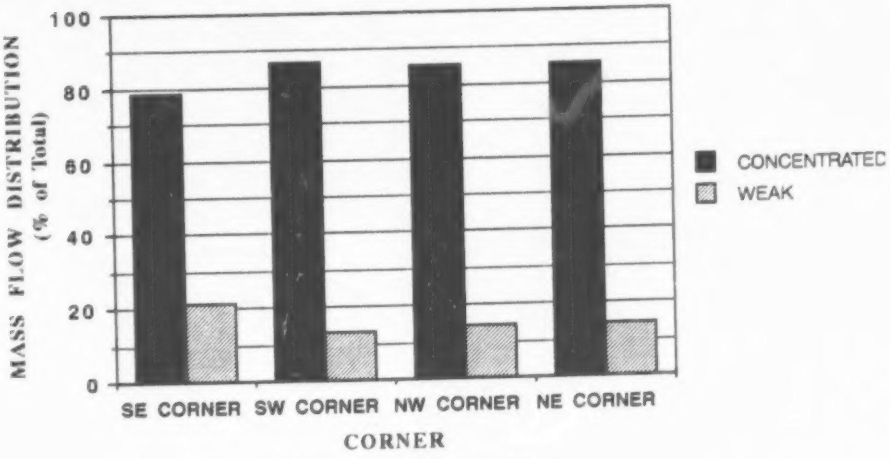


(B) COAL MASS FLOW

Figure 9: Primary Air Velocity and Coal Mass Flow Distribution
PM Firing System Upstream of PM Separator



(A) PRIMARY AIR DISTRIBUTION



(B) COAL MASS FLOW

Figure 10: Primary Air Velocity and Coal Mass Flow Distribution
PM Firing System Downstream of PM Separator

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The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

ENEL'S ONGOING AND PLANNED NO_x CONTROL ACTIVITIES

A.Benanti (1) - D.Bonolis (1) - R.Tarli (1) - A.Baldacci (1)
A. Piantanida (2) - A.Zennaro (3)

ABSTRACT

ENEL is implementing activities to improve the environmental impact of thermal power stations. Particularly as regards NO_x emissions, ENEL intends to adopt mainly low-NO_x burners and to install abatement systems of the SCR type.

The paper describes the program under way, the design criteria adopted for NO_x reduction in the furnace, and the first results obtained with demonstrative plants.

The steam generators that will undergo retrofitting are of both the tangential and front-firing types, and burn fuel oil, gas and coal. The capacities of the units involved are 320 MW and 660 MW.

1. FOREWORD

In 1988 over 67% of the overall electricity demand (191 TWh) in Italy was met with ENEL's power stations fired with fossil fuels (oil, coal and natural gas). Coal-fired stations supplied 27 TWh, thus covering 14% of the demand.

In the field of environment protection, from some years ENEL has followed an advanced policy. The environment has become one of the main items that influence ENEL's basic choices and planning.

One of the main targets is the drastic reduction of the emissions from both new and operating plants. In this connection, ENEL has to comply with three international protocols on reduction of emissions signed by the Italian Government: the Helsinki protocol of 1985, the ECE-ONU protocol and declaration signed in Sophia on 31 October 1988, and the European Community Directive for large combustion plants.

The first protocol covers the overall sulfur dioxide emissions, which

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(1) Ente Nazionale Energia Elettrica - Italy

(2) F. Tosi F.T.C. - Italy

(3) Ansaldo Componenti - Italy

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in 1993 shall have to decrease by 30% as compared to the 1980 emissions. For the share of its competence, ENEL will comply with the Helsinki undertakings three years in advance, that is, in 1990 as requested by a Decree of the Italian Ministry for the Environment.

In Sophia two protocols were signed for reduction of the overall national emission of nitric oxide; the first protocol was signed by almost all the western and eastern countries, and establishes that the present value of No_x emissions shall not be exceeded in the future. The second protocol was signed only by twelve countries, among which Italy, and establishes that by 1998 the overall national emissions of NO_x shall decrease by 30% versus the emissions of any year chosen from 1980 to 1986.

The CEE directive sets forth severe limits for emissions from each new large combustion plant, whereas for existing plants it sets forth limits to the overall emissions.

To meet the requirements concerning NO_x emissions, as a priority ENEL intends to make all the actions necessary to reduce emissions--through modifications to the combustion system--from all planned and operating plants, and then to adopt abatement systems of the high-dust SCR type particularly in plants fired with low sulphur content oil.

ENEL's Board of Directors is just now deciding on a first tranche of modifications to be made on a group of plants within 1993. Subsequently, all the plants will be modified making every effort to minimize plant unavailability. This requirement is essential owing to the difficulty ENEL will have in meeting the increase in power demand in the next five years as a consequence of abrogration of the nuclear programs and of the delays in the construction of new conventional plants.

The paper illustrates the efforts made by ENEL jointly with the national steam generator manufacturers (Ansaldo and Tosi) to reduce nitric oxide emissions through modifications to the combustion system.

2. ACTIVITIES UNDER WAY FOR NO_x REDUCTION THROUGH COMBUSTION MODIFICATIONS

Many activities have been planned and are under way to reduce NO_x emissions from ENEL's boilers in operation or under construction through modifications to the combustion system. The boilers being modified are manly of two types, that is, the front-firing type of Ansaldo make under the licence of Babcock & Wilcox, USA, and the tangential firing type of F.Tosi make under the licence of Combustion

Engineering.

Table 1 shows the configuration of the burners of the operating boilers that will be modified. The modifications will cover an overall installed capacity of 23815 MW, of which 29% from coal.

The units can be divided into nine different groups, depending on the combustion system arrangement (five for oil-fired units and four for coal-fired units). Furthermore, twelve new multifuel (coal, oil and gas) units are under construction for an overall capacity of over 6,500 MW. For these units the most recent available technologies have been adopted to reduce NO_x production in the furnace.

The program therefore provides for a series of activities that vary depending on the burner arrangement and on the type of fuel, and taking into account the possibility of simultaneous utilization of different fuels.

For a better understanding, the activities mentioned above are described separately for the two different types of boiler, (front-rear firing and tangential firing.)

3. ACTIVITIES UNDER WAY ON FRONT-REAR FIRING BOILERS

The activities belong to two categories, namely:

(a) Retrofitting of Existing Boilers (Cell Burners)

Most of the existing boilers adopt cell burners. The cells can be of different types:

- cells of two or three burners installed in coal designed units, which can be fired with coal or oil
- cells of three burners installed in oil units
- cells of three burners installed in oil designed units, which can be fired with oil or gas.

The solutions selected have not yet been qualified in full scale plants; therefore, for each solution it was deemed advisable to procede in phases:

- selection of a reference boiler to be modified as prototype
- characterization and operation tests
- analysis of the results and definition of the final solution;
- modifications to the existing boilers.

(b) Modifications to New Plants

The solutions chosen belong to the best proven technology of the Ansaldo/Babcock & Wilcox, though they have not yet been adopted in Italy. The solutions did not require a campaign of experiments on prototype.

3.1 Low-NO_x Combustion Tests with Cell Burners Units

The program of low-NO_x combustion tests with cell burners is divided into the following three campaigns.

POWER STATION	UNIT	FUEL	CAPACITY (MWe) PER UNIT	CELL NUMBER	BURNER NUMBER PER CELL	SCHEDULE
La Casella	3	oil	320	6	3	1987-88
Rossano C.	4	gas	320	6	3	1988
		oil				1989
Vado Ligure	4	coal	320	15	2	1990
		oil				1990

3.1.1 Low-NO_x combustion tests with oil units

In the years 1987-88 two types of tests were performed at La Casella Station:

- tests in normal operation conditions (18 burners in service)
- tests with 12 burners, of which the six upper burners were used as NO_x ports.

Further long-duration tests are still under way to carry out a more exhaustive analysis on the combustion atmosphere and on the furnace corrosion.

Fig. 1 illustrates the lay-out of the gas taps and of the corrosion panels installed on the boiler walls.

As concerns emissions, we note that:

- Operation with twelve burners and air immission from the upper burners reduces the NO_x concentration as compared to normal operation (18 burners in service, Fig. 2).
- Gas recirculation lowers NOx in both burner arrangements (18 and 12 burners in service, Fig. 3). We note that with gas recirculation up to 25% the reduction is considerable; beyond this value the reduction is quite low.
- Opening of the upper air registers has moderate influence on emissions, because the air leakage through the closed registers is considerable, that is, about 15% of the total combustion air versus 26-28% with registers open at 50%. With closed registers the lower burners operate in under-stoichiometric conditions (stoichiometric ratio about 0.88%).

As concerns NO_x production in the furnace, the atmosphere near the waterwalls was analyzed by measuring the O_2, CO, H_2S and NO_x

concentrations. The flue gas is extracted and conditioned for the analysis through adequate sampling lines. Gas extraction is performed through a penetration in the membrane, which allows tapping of the gas along the walls.

A first evaluation of the NO_x values shows that:

- The NO_x profile along the different walls varies greatly depending on the type of combustion (18 or 12 burners) and on the gas recirculation. In particular, we observe similar NO_x values at different elevations only with 18 burners, whereas with two-stage combustion the NO_x concentration increases with elevation. This means that at the considered elevations combustion is not yet completed. At any rate, the overall NO_x concentrations are lower than those measured with 18 burners. It should be noted that gas recirculation besides reducing the NO_x flattens the concentration profile.
- The trend of the O_2 concentration allows an exact evaluation of the reducing zones in the furnace. With 18 burners too, these zones are localized on the side walls, where the ultrasonic tests carried out on the tubes indicate the lower residual thicknesses. It is interesting to note that the O_2 concentration on the front and rear walls is very high, probably owing to the combustion air coming from the burners that is diverted along the walls.
- These typical trends are common to the various boiler loads; obviously, at lower loads NO_x is lower and O_2 is higher.

During the tests with 18 and 12 burners the metal temperatures and the thermal fluxes were measured, the latter by means of chordal thermocouples located where the maximum thermal flux is expected. Thus, it was possible to observe that with 12 burners in operation the flux increase due to the higher heat release in the combustion zone is limited and that the operation temperatures of the metal are still below the design limits.

3.1.2 Low NO_x combustion tests with gas-fired cell burners

The tests were performed on unit 4 of the Rossano Calabro station in November-December 1988. Three series of tests were performed:

- Baseline tests (18 burners in operation)
- Tests with 12 burners, orientable spuds, increased nozzle diameters and the same arrangement as above, and upper burners used as NO_x ports.
- Tests with 12 burners, orientable spuds, increased nozzle diameters, different nozzle arrangement, and upper burners used as NO_x ports.

During all the tests the vibrations of the buckstays and the pressure oscillations in the furnace were measured; the values obtained were low and therefore did not pose any problem.

A synthesis of the results is shown in the diagrams, where all the NO_x and CO concentrations are referred to dry gas with a 3% O_2 concentration.

We note that:

- operation with 12 burners and air immission through the upper burners entails a considerable reduction in the emission as compared with the 18 burners arrangement (see Fig. 4). At rated load, with $O_2 = 0.8\%$ and with the gas recirculation dampers closed, the NO_x emissions decrease from 690 mg/Nm^3 (18 burners) to about 490 mg/Nm^3 (12 burners with both gas nozzle arrangements).
- Opening of the gas recirculation dampers allows a further considerable reduction in the emissions (Fig. 5).
- Opening of the upper air registers has little influence on the emissions (Fig. 6).

This behaviour can be explained with the fact that even with closed upper registers the air flowing into the furnace through the latter is considerable; a first evaluation (based on the measurement of the differential pressure between windbox and furnace) shows that about 20% of the overall combustion air flows through the "closed" registers. Therefore, the lower burners operate in severe understoichiometric conditions (stoichiometric ratio 0.8-0.85% with $O_2 = 0.8\%$)

- The influence of the excess air on the NO_x and CO emissions is shown in Fig. 7.
- Orientation of the gas spuds (only standard nozzle arrangements were tested) influence NO_x emission significantly.
- The thermal fluxes and the metal temperatures measured with the 12-burner arrangement confirm the results of the tests with the oil-fired cell burners described above. The two-stage combustion carried out with 12 burners does not jeopardize structural stability of the boiler pressure parts.

3.1.3 Low NO_x combustion tests with coal

In Italy, forteen 320-MW boilers of this type are in operation; the boilers are fired with coal and oil and are equipped with two or three register cell burners. The particular configuration of this system, which is characterized by a very reduced vertical pitch and the small size of the furnace, do not allow replacement of the existing burners with low-NO_x burners or opening of ports for the post combustion air.

On the basis of the technology developed by Babcock & Wilcox in cooperation with EPRI and experimented on reduced scale, only the two lower burners of the three register cells and the lower burner of the two register cells are operated, whereas the upper burner is used for immission of the post-combustion air (Ref. 1). For a full-scale demonstration of this technology, use will be made of unit 4 of Vado Ligure station (320 MW).

The once-through UP boiler was designed by Babcock & Wilcox and built by Ansaldo, and is equipped with 30 burners arranged in 15 two-register cells.

The design is already completed; therefore, the modifications will be carried out during the scheduled outage in autumn '89, and the tests will be performed in 1990.

The test campaign aims mainly at evaluating the following aspects of the new combustion system before modifying all the remaining boilers:

- effectiveness of the new system in significantly reducing NO_x emissions without adverse effects on boiler operation (in both coal and oil firing).
- Study on short-term corrosion in order to assess the effect of the reducing atmosphere in the combustion zone in terms of chemical attack on the waterwall tubes. Therefore, gas samples will be drawn systematically to analyze the content of potentially corrosive components, and the initial and final thickness will be measured of calibrated and instrumented samples. The whole test campaign should last 6-8 months.

As regards the three-register cells their performance will be assessed with a 35-MWth scaled down model installed in a test rig.

Design of the modified solutions provides for installation of the equipment for natural gas combustion in order to develop a multi-fuel combustion system, following ENEL's policy of maximum fuel diversification.

3.1.4 Preliminary conclusions

On the basis of the results of the oil and gas tests, we can make the following observations and outline the actions aiming at attaining the final plant arrangement for continuous low-NO_x operation.

- Staged combustion does not jeopardize mechanical stability of the waterwall tubes; therefore, modifications are not required for the pressure parts of existing boilers.
- The upper burners will be replaced with adequate air registers that operate as after-air ports, to obtain improved air inlet for a more efficient combustion and a better control of the stoichiometric conditions in the burner zone. The latter aspect will become even

more important should the corrosion tests indicate a high corrosion rate, which can be reduced by controlling the stoichiometric conditions in the furnace.

3.2 New Boilers Under Construction

The boilers discussed here have the following original design characteristics:

(a) Four UP boilers, of Babcock & Wilcox design, for Brindisi Sud Station:
  - capacity: 660 MW
  - fuel: coal and oil
  - 56 Babcock & Wilcox burners of the dual-register type.

(b) Two natural circulation boilers for the Tavazzano Station:
  - capacity: 320 MW
  - fuels: coal and oil
  - 30 Babcock & Wilcox burners of the dual-register type.

During construction of the boilers it was decided to make the necessary modifications to obtain maximum reduction of the NO_x emissions and at the same time to have the possibility of firing gas as well.

The first 660-MW unit, which had already undergone the hydraulic test, was equipped with NO_x ports and with the system for mixing recirculated flue gas and combustion air. The original burners were modified by installing in the throat a multi-nozzle ring for natural gas firing.

The remaining 660- and 320-MW units were further modified by replacing the original dual register burners with Babcock & Wilcox low-NO_x burners of the XCL type.

The XCL burner was modified to add the components required for natural gas firing; a full-scale prototype was experimented on a test rig of Riley Stoker in the USA in early 1988.

The first startup of unit 1 is expected in April 1990 for the 660-MW boilers, and in Autumn 1990 for the 320-MW boilers.

4. ACTIVITIES UNDER WAY ON TANGENTIAL-FIRED BOILERS

Here too, the activities can be grouped into the two following categories:

(a) Retrofitting of Existing Boilers

To attain the low-NO_x emission goal, ENEL has prepared a program that utilizes an advanced system for low NO_x combustion that is being developed by Combustion Engineering. The program covers the

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following phases:

- Laboratory experiments of an advanced combustion system.
- Analysis of the results and application of the advanced system to a full-scale boiler.
- Tests for characterization and operation of the boiler before and after the modifications.
- Analysis of the results and selection of the final solutions for application to the other boilers.

(b) Modifications to New Plants

Because of the advanced state of design of Fiume Santo, it was essential to proceed with tangential system with proven experience. The burners were purchased from C.E. and installed in the Fiume Santo unit.

The schedule for Gioia Tauro permits a review of the results from the Fusina demonstration before a final design is chosen.

4.1 Combustion Tests

The test Program for the advanced combustion system will be carried out as follows:

Boiler	Fuel	MW(th)	Schedule
C.E. Boiler Simulation Facility	Coal	15 MW(e)	Nov.-Dec. 1988
Fusina	Coal	160 MW	1989

4.1.1 Fusina project

4.1.1.1 Low-NO_x Combustion System

The Fusina Station is equipped with four TOSI-CE tangential-firing boilers of the multi-fuel type but firing mainly coal. Of the boilers, two are rated 320-MW and, two 160 MW. One of the 160-MW boilers will be equipped with a low-NO_x combustion system consisting of:

- Overfire Air Ports (OFA)
- Concentric Firing System (CFS)
- Vertical Grouping of Coal Nozzles

The system delays mixing of the fuel and of the combustion air thus reducing NO_x emissions to values that should range around 400 mg/Nm^3 (referred to dry gas with 6% O_2).

4.1.1.2 Laboratory Activity

The system described above posed several basic technical problems that had to be studied and solved through laboratory research before the final design. In particular, the following items were investigated:

- Reduction obtained in NO_x emissions with different nozzle groupings.
- Optimization of the air flow through the intermediate auxiliary air compartments to attain the best operation condition.
- Influence on the NO_x of the amount of air introduced through the conventional OFA ports and through the separate OFA ports (HSHP).
- Effects on the unburnt of the coal nozzle grouping and of the HSHP OFA installation.
- Variation of the required pressure drop for the HSHP OFA as a function of the distance from the furnace outlet.
- Optimization of the burner nozzles.

The laboratory tests are being performed on the 50-million Btu/h boiler simulation facility (BSF) at the KDL laboratory of Combustion Engineering in Windsor, USA. Several Different configurations of coal nozzle groupings and of the HSHP OFA are being compared. The first coal used was American coal having similar characteristics to the coal now being burned at the Fusina station in terms of fixed carbon-to-nitrogen ratio, nitrogen in the fuel, and ash fusion temperature.

4.1.1.3 Future Programs for the Fusina Station

The obtained results will be applied to the Fusina 160-MW boiler that will operate as prototype for the new low-NO_x combustion system. A test campaign for coal firing was carried out to have a fingerprinting of the boiler operation.

In the coming months these tests will be performed with oil and gas firing and with different coals. Then, the modifications will be carried out, of which the most importat are:

(a) Installation of separate OFA ports on the four corners of the boiler, designed for 25-30% of the total combustion air. To optimize combustion it will be possible to orient the air nozzles either vertically or horizontally.

(b) Re-positioning of the coal nozzles by adequate grouping, reproportioning of the auxiliary air compartments, installation of conventional OFA ports in the upper part of the windbox. Through the OFA ports 10-20% of the total combustion air will be introduced. The intermediate air nozzles can be oriented on the horizontal plane in order to divert the combustion air towards the waterwalls (CFS system).

(c) Installation of a booster fan to give sufficient pressure to the air flowing through the HSHP OFA ports.

4.1.2 Fiume Santo Station (2 x 320 MW)

The two boilers for the new 320-MW units of the Fiume Santo station were in advanced construction when it was decided to modify the combustion system in order to limit NO_x production. The choice fell on the installation of PM coal burners of Japanese technology supplied by C.E. (Ref. 2) Since the new windbox housing the tangential burners was higher, the furnace height was increased by 2.5 m. Other modifications, such as replacement of the mill exhausters with the pressurized primary air system and a few minor changes to the reheater surfaces were also included.
The boilers are being assembled and it is expected that the first unit will begin operation in 1990.

4.1.3 Gioia Tauro station (4 x 660 MW)

The boilers of this station will be equipped with the system being installed in Fusina demonstration unit.

4.1.4 Oil - and gas-fired boilers

ENEL intends to modify the combustion system of this type of boilers already in operation, mainly by adopting the OFA and the flue-gas recirculation techniques.

5. CONCLUSIONS

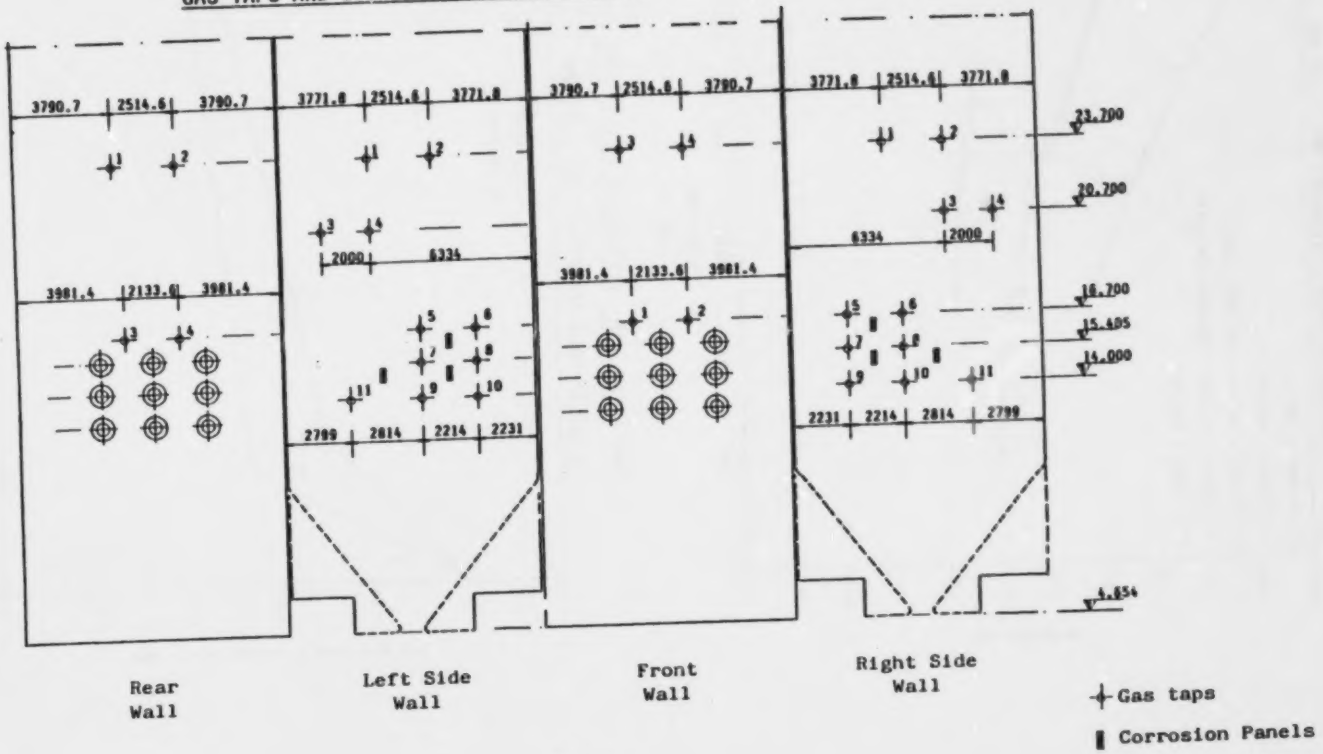
ENEL's efforts in the field of NO_x reduction entailed an extended activity program carried out jointly with the national steam generator manufacturers.
The different types of combustion systems and the fact that the boilers are generally designed for two or more types of fuel sometimes prevent the utilization of proven technologies, mainly as regards retrofitting where the solutions are conditioned to the intrinsic characteristics of the boiler, to the unit unavailability and to the costs required to perform the modifications. Extensive programs were therefore implemented to demonstrate the validity of the solutions hypothesized for the various types of steam generators. The first studies and results have proven that the goals set by ENEL can be attained with the programs under way.

REFERENCES

1. Clark W.J., La Rue A.D., Liang A.D. and Eskinazy D. Large Scale Testing and Development of the B&W Low NO_x Cell Burner. Presented to Joint Symposium on Stationary Combustion NO_x Control, New Orleans, 1987.

2. Y. Takahashi, T. Kumimoto, K. Tokuda, T. Kawamura, S. Kaneko. Development of Pulverized Coal Fired Low NO_x PM Burner Technical Review, October 1981.

LA CASELLA - UNIT NO. 3
GAS TAPS AND CORROSION PANELS LOCATION


3790.7
2514.6
3790.7
3981.4
2133.6
3981.4
3771.8
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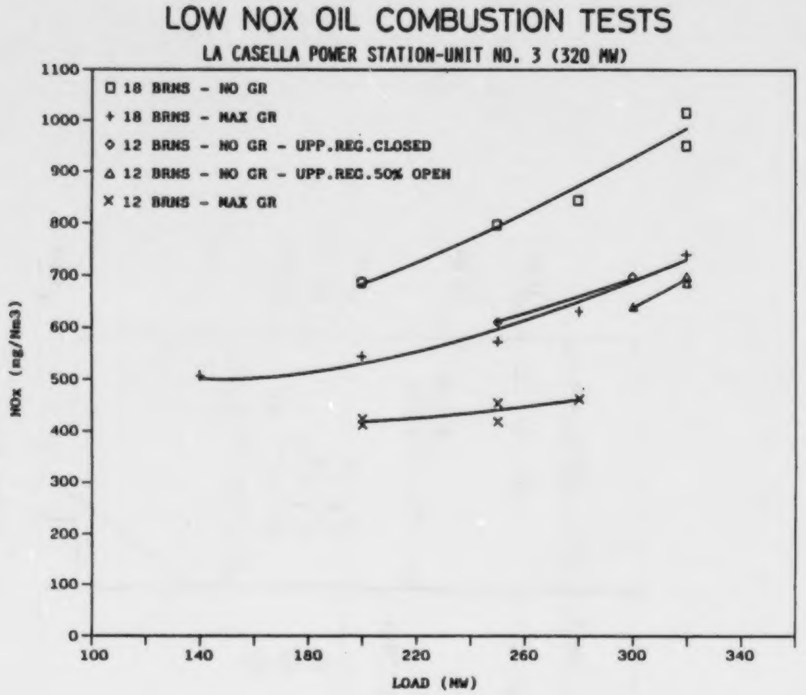
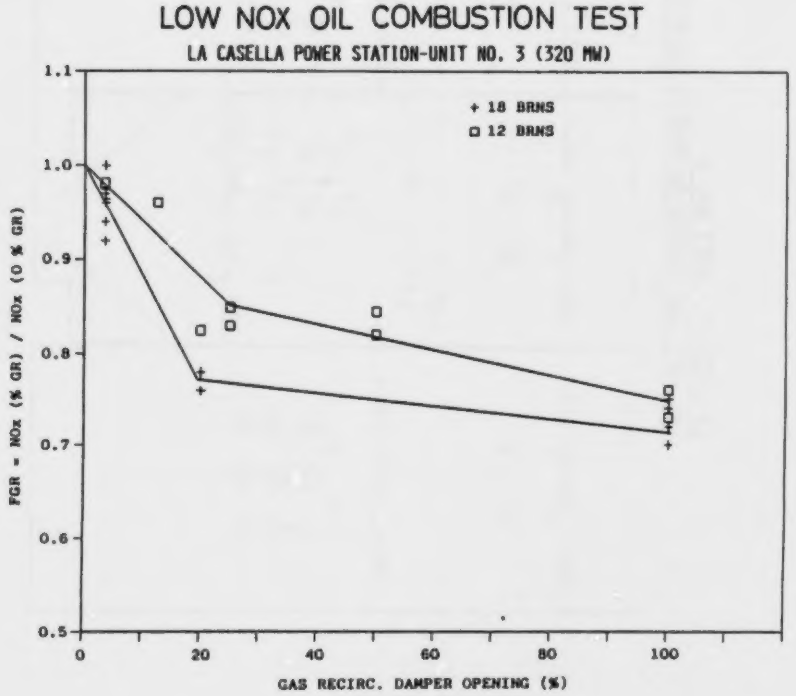
2799
2814
2214
2231
3790.7
2514.8
3790.7
3981.4
2133.6
3981.4
3771.8
2514.6
3771.8
6334
2000
2231
2214
2814
2799
23.700
20.700
16.700
15.405
14.000
4.854
1
2
3
4
5
6
7
8
9
10
11
Rear Wall
Left Side Wall
Front Wall
Right Side Wall
Gas taps
Corrosion Panels

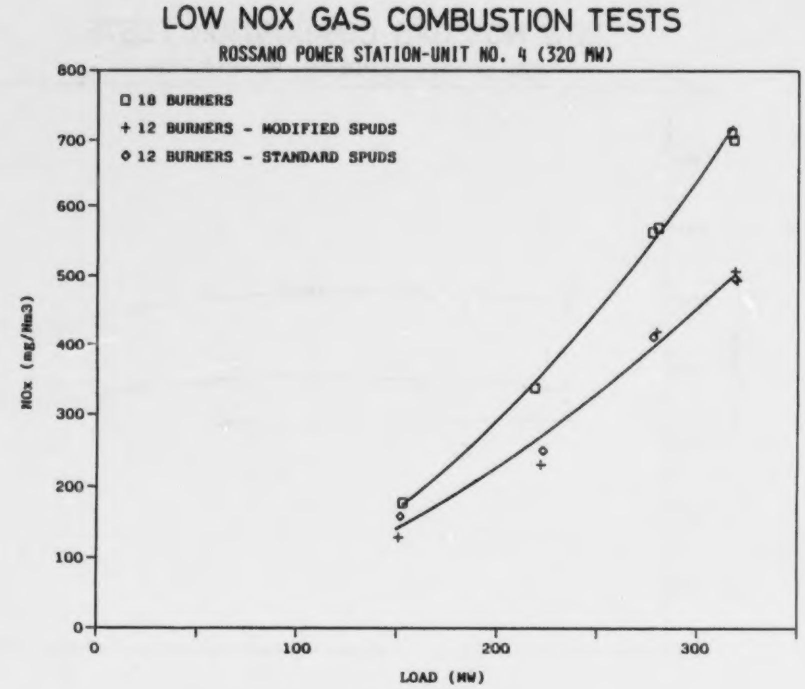
- FIG. 1 -


LOW NOX OIL COMBUSTION TESTS
LA CASELLA POWER STATION-UNIT NO. 3 (320 MW)
□ 18 BRNS - NO GR
+ 18 BRNS - MAX GR
◇ 12 BRNS - NO GR - UPP.REG.CLOSED
△ 12 BRNS - NO GR - UPP.REG.50% OPEN
× 12 BRNS - MAX GR
NOx (mg/Nm3)
1100
1000
900
800
700
600
500
400
300
200
100
0
100
140
180
220
260
300
340
LOAD (MW)

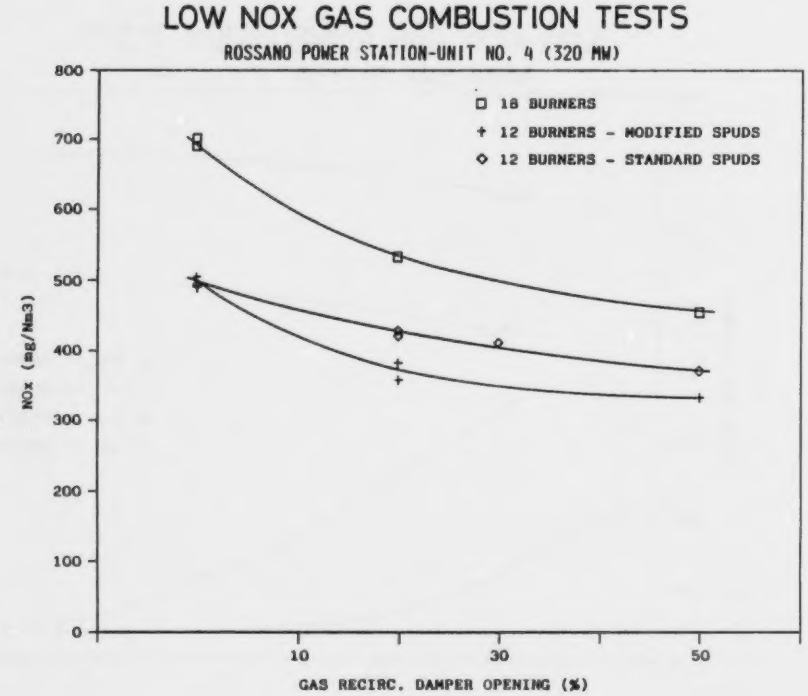
- FIG. 2 -


LOW NOX OIL COMBUSTION TEST
LA CASELLA POWER STATION-UNIT NO. 3 (320 MW)
+ 18 BRNS
□ 12 BRNS
FGR = NOx (% GR) / NOx (0 % GR)
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0
20
40
60
80
100
GAS RECIRC. DAMPER OPENING (%)

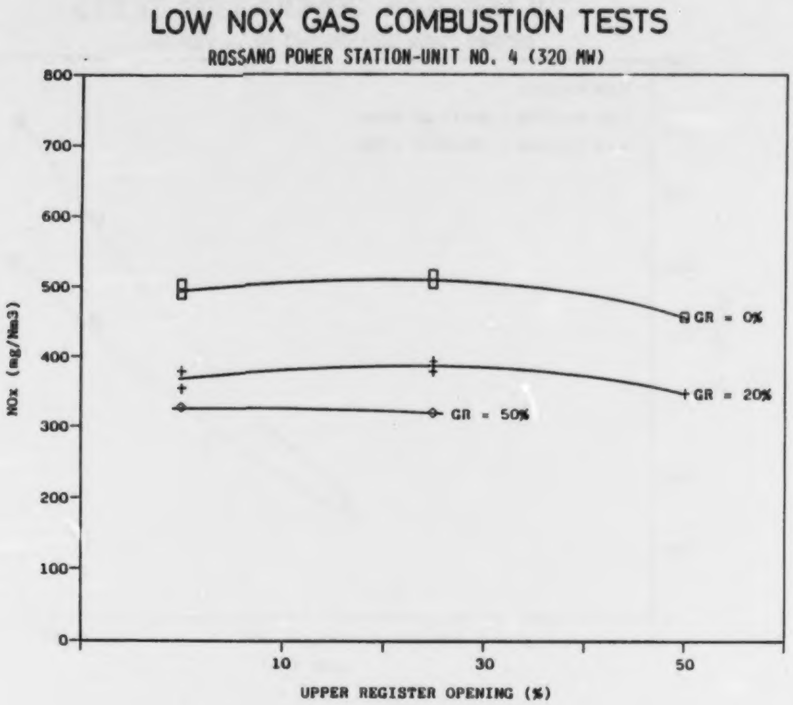
- FIG. 3 -


LOW NOX GAS COMBUSTION TESTS
ROSSANO POWER STATION-UNIT NO. 4 (320 MW)
18 BURNERS
12 BURNERS - MODIFIED SPUDS
12 BURNERS - STANDARD SPUDS
NOx (mg/Nm3)
800
700
600
500
400
300
200
100
0
0
100
200
300
LOAD (MW)

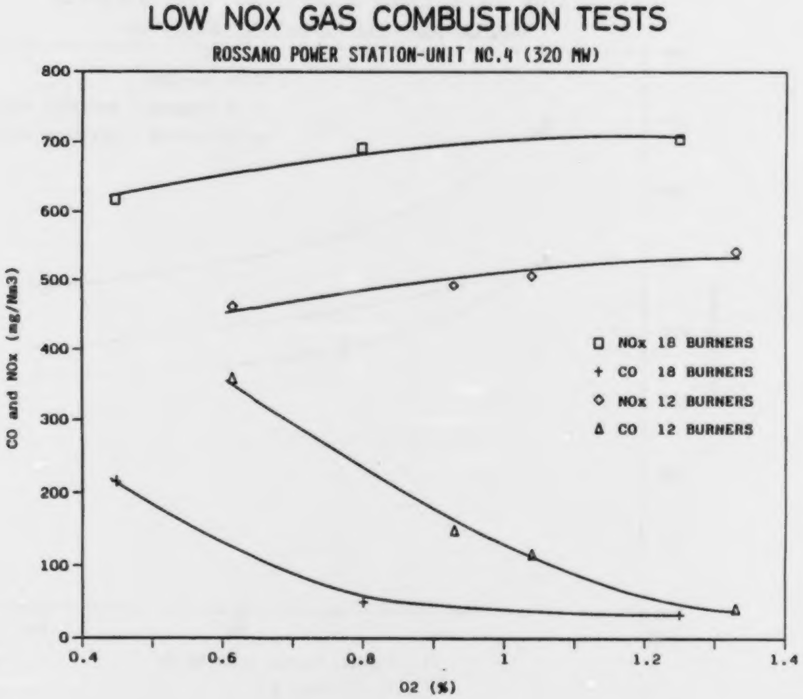
- FIG. 4 -


LOW NOX GAS COMBUSTION TESTS
ROSSANO POWER STATION-UNIT NO. 4 (320 MW)
18 BURNERS
12 BURNERS - MODIFIED SPUDS
12 BURNERS - STANDARD SPUDS
NOx (mg/Nm3)
800
700
600
500
400
300
200
100
0
10
30
50
GAS RECIRC. DAMPER OPENING (%)

- FIG. 5 -


LOW NOX GAS COMBUSTION TESTS
ROSSANO POWER STATION-UNIT NO. 4 (320 MW)
NOx (mg/Nm3)
800
700
600
500
400
300
200
100
0
10
30
50
UPPER REGISTER OPENING (%)
GR = 0%
GR = 20%
GR = 50%

- FIG. 6 -


LOW NOX GAS COMBUSTION TESTS
ROSSANO POWER STATION-UNIT NO.4 (320 MW)
CO and NOx (mg/Nm3)
800
700
600
500
400
300
200
100
0
0.4
0.6
0.8
1
1.2
1.4
O2 (%)
□ NOx 18 BURNERS
+ CO 18 BURNERS
◇ NOx 12 BURNERS
△ CO 12 BURNERS

- FIG. 7 -

BURNER CONFIGURATION OF ENEL's EXISTING BOILERS
(CAPACITY > 200 MWe)

		FRONT-REAR BURNERS			TANGENTIAL FIRING BURNERS
		Two register cells	Three register cells	Parallel Flow	
OIL FIRED BOILERS					
CHIVASSO	Unit 5 (*)				
PIACENZA	Units 3,4				660
LA CASELLA	Units 1,2,3,4		1,280		
OSTIGLIA	Units 1,2,3,4				1,320
TURBIGO LEV.	Unit 1 (*)				
	Unit 2		320		
	Units 3,4				660
SERMIDE	Units 1,2,3,4			1,280	
TAVAZZANO	Units 5,6			640	
MONFALCONE	Units 3,4			640	
PORTO TOLLE	Units 1,2,3,4				2,640
TORREV. SUD	Units 2,3,4				960
TORREV. NORD	Units 1,2,3,4			2,640	
ROSSANO	Units 1,2,3,4		1,280		
TERMINI I.	Units 4,5		640		
PRIOLO G.	Units 1,2				640
TOTAL CAPACITY (MW)		0	3,520	5,200	6,880
COAL FIRED BOILERS					
LA SPEZIA	Units 1,2,4				1,235
	Unit 3		600		
VADO LIGURE	Units 1,2,3		990		
	Unit 4	330			
PIOMBINO	Units 1,2,3,4	1,280			
FUSINA	Units 3,4				640
BRINDISI NORD	Units 1,2	640			
	Units 3,4		640		
S. FILIPPO	Unit 5		320		
	Unit 6	320			
SULCIS	Units 1,2,3 (*)				
TOTAL CAPACITY (MW)		2,570	2,550	0	1,875

(*) Units equipped with circular burners on the front wall (total capacity 1,220 MW).

- Tab. 1 -

Session 3

COMBUSTION NO$_x$ DEVELOPMENT II

Chairman: R. Hall, EPA

The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

PILOT EVALUATION OF REBURNING FOR CYCLONE BOILER NO_x CONTROL

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ABSTRACT

There are currently no commercially-demonstrated combustion modification techniques for cyclone boilers which reduce NO_x emissions. The emerging reburning technology offers cyclone boiler owners a promising alternative to expensive flue gas cleanup techniques for NO_x emission reduction. Reburning involves the injection of a supplemental fuel (natural gas, oil, or coal) into the main furnace in order to produce locally reducing stoichiometric conditions that convert NO_x produced in the main combustion zone to molecular nitrogen, thereby reducing overall NO_x emissions. This paper presents the encouraging pilot-scale results obtained using natural gas, fuel oil, and pulverized coal (PC) as reburning fuels. At a reburning zone stoichiometry of 0.9, 67% NO_x reduction for gas and oil reburning and 57% for coal reburning were achieved. Flue gas recirculation (FGR) was introduced at the reburning burners, and improved mixing and NO_x reduction. FGR was more effective with PC reburning. Carbon monoxide (CO) emissions levels were low (less than 30 ppm) throughout the various optimum test conditions. Although the carbon content of the fly ash increased, the overall combustion efficiencies were insignificantly lower for all the reburning fuels. Furnace exit gas temperatures (FEGTs) increased by less than 50°F during reburning operation. Capital costs for reburn technology on a 200-MW cyclone-fired unit can range from about $22/kW (gas) to $41/kW (coal). Ten-year levelized incremental busbar costs were sensitive to assumed reburn fuel prices. Lower projections were 1.7 mills/kWh (coal), 2.3 mills/kWh (gas), and 3.3 mills/kWh (oil). Babcock & Wilcox (B&W) is presently starting a full-scale 100-MW utility cyclone reburn demonstration project with Wisconsin Power & Light per the U.S. Department of Energy's (DOE's) Clean Coal II program.

INTRODUCTION

The Electric Power Research Institute (EPRI) and the Gas Research Institute (GRI) contracted with the Babcock & Wilcox Company (B&W) to perform a pilot-scale evaluation of the reburning technology for cyclone boiler NO_x emissions control. These pilot tests were justified via a previous EPRI-sponsored (Project RP-1402-30) engineering feasibility study of reburning for cyclone boilers performed by B&W. The feasibility study revealed that the majority of cyclone-equipped boilers could successfully apply this technology in order to reduce their NO_x emission levels by approximately 50 - 70% (1). The major criteria that substantiated this potential was that sufficient furnace residence time does exist within these boilers in order to apply the technology. Thus, based upon this conclusion, the next level of confirmation – pilot-scale evaluation – was justified. These pilot tests involve evaluating the potential of natural gas, oil, and coal as the reburning fuel in reducing NO_x emissions. This paper focuses on the results obtained during the evaluation of these three reburning fuels.

There are presently 105 operating, cyclone-equipped utility boilers representing approximately 14% of pre-NSPS coal-fired generating capacity (over 26,000 MW). However, these units contribute approximately 21% of the NO_x emitted since their inherent turbulent, high-temperature combustion process is conducive to NO_x formation. Although the majority of cyclone units are 20 - 30 years old, utilities plan to operate many of these units for at least an additional 10 - 20 years. The potential of future acid rain control and the midwest location of the majority of these units may target these boilers for NO_x emission control.

Cyclone-equipped boilers have a unique configuration that prevents application of standard low-NO_x burner technology – that is, that the combustion occurs within a water-cooled horizontal cylinder attached to the outside of the furnace. Furthermore, other conventional NO_x reduction techniques such as two-stage combustion cannot be applied to the full extent due to associated cyclone operational concerns (cyclone corrosion). The use of selected catalytic reduction (SCR) technology offers promise of controlling NO_x from these units, but at high capital and operating costs. Reburning is therefore a promising alternative NO_x reduction approach for cyclone-equipped units at more reasonable capital and operating costs.

Reburning technology involves injection of a second fuel into the main furnace (above the cyclone region) to produce a secondary combustion zone where a reducing atmosphere exists. These local chemical reducing conditions convert NO_x to molecular nitrogen, thus destroying a portion of the NO_x produced in the primary cyclone combustion zone. The reburning technology had never been applied (bench-/pilot-/commercial-scale) to cyclone-equipped boilers. Although numerous reburning studies for natural gas-/oil-/PC-fired boilers have been performed, it is difficult to extrapolate these results directly to cyclone units due to inherent differences in cyclone boiler design and operation. The characteristics of cyclone units that may affect NO_x reduction, solids deposition, and efficiency of back-end equipment when applying this technology include:

- Higher initial primary NO_x levels (600 - 1400 ppm at 3% O_2)
- Lower char/ash carryover to the main furnace due to the cyclone slagging capabilities
- Different convective pass and downstream particulate equipment design due to the lower fly ash loadings

The purpose of the pilot-scale tests was to substantiate/expand on the results obtained from the engineering feasibility study and to assess the potential NO_x emission capabilities of the process. This information will aid in identifying the potential commercial application of the technology. The following summarizes the specific objectives of the test program:

- Evaluate the major process parameters such as reburning/main combustion zone stoichiometries, reburning fuel type and quantity, and reburning/burnout zone residence times.

- Determine effects of reburning:
  - The degree of slagging/fouling in the upper furnace and convection pass
  - Combustion efficiency (based upon unburned combustibles and CO emissions)
  - Corrosion potential
  - Changes in furnace exit gas temperature

- Maximize NO_x reduction while maintaining combustion conditions compatible with design and operation of cyclone-equipped boilers.

BACKGROUND

The cyclone furnace consists of a cyclone burner connected to a horizontal water-cooled cylinder called the cyclone barrel (Figure 1). This auxiliary furnace was an attractive alternative to pulverized coal (PC) by providing the ability to burn low-grade coals, significantly reducing fly ash in the flue gas, requiring less fuel preparation equipment, and allowing for a reduction in total boiler size. Crushed coal and air are introduced through the cyclone burner into the cyclone barrel. The larger coal particles are thrust out to the barrel walls where they are captured and burned in the molten slag layer which has formed, while the finer particles burn in suspension. The mineral matter melts, exits the cyclone furnace from a tap at the cyclone throat, and is dropped into a water-filled slag tank. The flue gases and remaining ash leave the cyclone and enter the main furnace.

No commercially-demonstrated combustion modifications have significantly reduced NO_x emissions without adversely affecting cyclone operation. Past tests with combustion air staging achieved 15 - 30% reductions (2)(3). Cyclone tube corrosion concerns due to the resulting reducing conditions were not fully addressed because of the short duration of these tests. Further investigation of staging for cyclone NO_x control was halted due to utility corrosion concern. Additionally, since no mandatory Federal/State NO_x emission regulation was enforced, no alternative technologies were pursued.

The recent emergence of the reburning technology offers a promising alternative to conventional combustion controls and SCR systems. During the early 1980s, Tokyo Electric Power Company (Japan) and Babcock-Hitachi K.K. (BHK) jointly developed a technology known as in-furnace NO_x reduction (IFNR) to reduce NO_x emissions from natural gas-, oil-, and coal-fired furnaces. B&W is the exclusive licensee of BHK's IFNR process. The technology, a version of the process widely known in the industry as reburning, is based upon extensive laboratory research and has been proven in subsequent pilot- and full-scale operation in Japan. BHK has applied IFNR as a retrofit technology to ten wall-fired utility boilers in Japan. The retrofit units are natural gas, oil, and coal fired units ranging from 175 to 700 MW in size. BHK's pilot- and full-scale experience has demonstrated typical NO_x

emission levels shown in Table 1. Adapting this technology to the inherent characteristics of cyclone boilers was reviewed/determined during the aforementioned B&W engineering feasibility study. Based on the results of the study, it is estimated that a nominal 60% NO_x emissions reduction could be achieved from cyclone boilers with the use of reburning. Table 1 identifies these anticipated levels.

REBURNING PROCESS DESIGN CRITERIA

The reburning process employs multiple combustion zones in the furnace, as shown in Figure 2. The main combustion zone is operated at a reduced stoichiometry and has the majority of the fuel input (70 - 85% heat input). The majority of investigations on natural gas-/oil-/coal-fired units have shown that the main combustion zone of the furnace should be operated at a stoichiometry of less than 1.0. This operating criteria is impractical for cyclone units due to the potential for highly corrosive conditions, since most cyclones burn high-sulfur, high-iron content bituminous coals. To avoid this situation and its potentially catastrophic consequences, the cyclone main combustion zone was determined to be operated at a stoichiometry of no less than 1.1 (2% excess O_2).

The balance of fuel is introduced above the main combustion zone (cyclones) in the reburning zone through reburning burners. To protect the tubes around the reburning burners in the reburning zone from fireside corrosion, some air is introduced through these burners. The burners are operated in a similar fashion to a standard wall-fired burner. The furnace reburning zone is operated at stoichiometries in the range of 0.85 - 0.95 in order to achieve maximum NO_x reduction based on laboratory/actual boiler application results (4)(5).

The balance of the required combustion air – totaling 15 - 20% excess air at the economizer outlet – is introduced through overfire air (OFA) ports. These ports are designed with adjustable air velocity controls to enable optimization of mixing for complete fuel burnout prior to exiting the furnace.

Pilot- and field-scale studies by BHK and other researchers (4 - 7) have defined acceptable limits of residence times in the reburning zone. A 50 - 60% reduction can be achieved at residence times greater than 0.45 second. In order to complete combustion (based on B&W/BHK experience with staged combustion), about 0.65 second residence time is required. Thus, a total of about 1.1 seconds is required between the reburning ports and furnace exit.

PILOT REBURNING TEST PROGRAM

Technical Objectives

The technical objectives of this project are to demonstrate NO_x reductions of nominally 50 - 60% while maintaining acceptable cyclone/boiler operating conditions. Three reburning fuels were evaluated while operating under various anticipated full-scale simulated reburning conditions. Table 2 summarizes the various ranges of reburning criteria that were evaluated for NO_x reduction capability. Main cyclone/reburning burners fuel splits, reburning fuel type, furnace stoichiometries, and furnace residence times were varied. Additional variables that were evaluated include mixing, corrosion potential, fireside deposition, and combustion efficiency. The results will be utilized to confirm/expand the Phase I engineering feasibility study.

The major areas of technical uncertainty that were identified in the feasibility case studies and were evaluated during the pilot tests for all reburning fuel types include:

- NO_x reduction potentials of the reburning fuels when operating in a cyclone boiler environment of high initial primary NO_x levels and low char carryover to the main furnace (high char carryover increases available, unconsumed oxygen in the reburning zone)
- Optimization of process parameters for cyclone application
- Effects on increased solids deposition with coal reburning in the upper furnace and convective section
- Corrosion throughout the furnace
- Unburned combustibles and FEGT changes

Research Facility

B&W's 6-million Btu/hr Small Boiler Simulator (SBS) was utilized to perform the pilot-scale cyclone reburning tests (Figure 3). The SBS is fired by a single, scaled-down version of B&W's cyclone furnace. Coarse pulverized coal (44% through 200 mesh), carried by primary air, enters tangentially into the burner. (Pulverized coal had to be utilized in the SBS instead of crushed coal to obtain complete combustion in this small cyclone.) Preheated combustion air at 700°F enters tangentially into the cyclone furnace. The larger coal particles are captured and burn in the molten slag layer formed within the cyclone furnace, while the finer particles burn in suspension. The mineral matter melts, exits the cyclone furnace from the tap at the cyclone throat, and is dropped into a water-filled slag tank. Only 15 - 20% of the ash leaves the cyclone with the flue gases and enters the furnace.

The furnace is water-cooled and simulates the geometry of B&W's single-cyclone, front-wall fired cyclone boilers. It consists of four separate water-cooled sections. The lower part of the furnace can be converted to a PC-firing scheme. The SBS facility has been operating for a total of six years, with the last three years being operated in the cyclone configuration. This cyclone facility has been proven to simulate typical full-scale cyclone units via furnace/convective pass gas temperature profiles and residence times, NO_x levels, cyclone slagging potential, ash retention within the resulting slag, unburned carbon, and fly ash particle size. A summary of these comparisons is shown in Table 3.

The inside surface of the furnace is insulated to yield a FEGT of 2265°F at the design heat input rate of 6-million Btu/hr. A water-cooled tube bank simulates the flue gas time/temperature history inherent in full-scale cyclone convective passes. The tube bank consists of four separate sections for simulating a secondary superheater, reheater, primary superheater, and economizer. Each section consists of a water-cooled jacket and tubes to quench the flue gases. All four sections are connected to a common atmospheric drum. This use of convective tubes to cool the gas, in conjunction with the cyclone furnace, makes this a unique facility among pilot-scale combustors.

Two reburning burners were installed on the SBS furnace rear wall at an elevation above the cyclone burner/barrel. The facility is capable of firing natural gas, oil, or coal at the reburning burner region. The multi-fuel reburning burners are designed to accommodate the required velocities for furnace penetration and also to allow for enough flexibility for varying mixing characteristics. Each burner consists of essentially two zones with the outer zone housing a set of spin vanes while the inner zone contains the reburning fuel injector. Air and flue gas recirculation (FGR) can be introduced through the outer zone. The natural gas/oil burners also have the capability to bias the air/FGR flow between the inner/outer zones.

OFA ports are available on both the front and rear walls of the SBS at three elevations, with each elevation containing two ports. Locating the OFA ports at different elevations assists in assessing the effects of residence time on fuel burnout and NO_x reduction.

The SBS furnace and convection pass sections are equipped with numerous observation ports at different elevations to allow for complete evaluation of the process under investigation. In-furnace probing is performed at the port locations in order to determine temperatures and gas/solids composition.

Two air-cooled deposition probes are available in the convective section (simulating secondary superheater and reheater tubes) in order to allow for fouling (deposition) studies to be performed. These probes are equipped with thermocouples for measuring metal wall and inlet/outlet air temperatures. The probe metal temperatures are maintained at typical boiler tube temperature in order to assure meaningful ash deposition results. The effect of ash deposition on heat transfer is determined by energy balance calculations for each probe. In addition, a simulated commercial sootblower is available to determine the required sootblower pressure necessary to remove the deposits and restore maximum heat flux potential.

PILOT-SCALE RESULTS

The pilot-scale cyclone project reported herein includes the baseline and reburning tests. The baseline tests are performed under normal cyclone operating conditions and identify the benchmark data to which the subsequent reburning test results are compared. The reburning tests involved the installation/operation of two reburning burners and two OFA ports (at two different elevations). The reburning burners have the flexibility of varying the degree of mixing via changing reburn fuel injector type, spin vane location/angle, and addition of FGR. Critical data collected for both the baseline and reburning phases include NO_x, CO, O_2, and unburned combustible levels. In addition, gas temperature profiles throughout the furnace were measured. All the tests were performed while utilizing a Pennsylvania Kittanning seam coal as the main cyclone fuel. The same Kittanning coal ground to 85% <200 mesh was utilized during the coal reburning tests. The coal, oil, and natural gas analyses are shown in Table 4. The following paragraphs describe the results of these tests.

Baseline Tests

Figure 4 illustrates the NO_x emission levels obtained during the baseline tests. Operating the cyclone at 6-million Btu/hr results in a baseline NO_x level of 920 ppm at 3% excess O_2. NO_x emissions increased by approximately 40 ppm per each percentage point increase in excess O_2. Reducing furnace load to 4.3-million Btu/hr decreased the NO_x emission level to 850 ppm at 3% excess O_2. As excess O_2

changes, the slope of the resulting NO_x curve is the same as that observed at full load. Firing natural gas in the cyclone at 6-million Btu/hr resulted in NO_x emissions of 455 ppm at 2% excess O_2 (typical operating excess O_2). Reducing the oxygen to 1% resulted in the same NO_x level as that observed at 2% O_2 (455 ppm), but increasing the oxygen to 3% excess O_2 reduced the NO_x level to 392 ppm. These resulting NO_x levels can be explained via the cyclone exit gas temperatures and the various mechanisms of NO_x formation.

Cyclone exit temperatures were measured utilizing an optical pyrometer. At 6-million Btu/hr (coal firing), the temperatures changed from 2950° to 2850°F at 2 to 4% O_2, respectively. At 4.3-million Btu/hr, the same trend was observed at 2 to 4% O_2 (2800° to 2700°F). Natural gas firing at 6-million Btu/hr showed temperatures of 2640° to 2570°F from 1 to 3% O_2. The various trends of NO_x emission levels versus excess oxygen can be explained by the different mechanisms of NO_x formation. During natural gas firing, thermal NO_x is the major mechanism of NO_x formation. Thus, NO_x levels decreased as the excess oxygen increased since the cyclone exit temperature was also observed to decrease. During coal firing, fuel NO_x is another contributor along with thermal NO_x. Since fuel NO_x increases with increasing excess oxygen, the overall NO_x levels were observed to increase with higher O_2.

Reburning Tests

The two reburning burners were located at the rear furnace wall of the SBS. Kittanning coal was fired in the cyclone during all test phases and the cyclone was operated at 65 to 85% of total load under excess air conditions. Reburning fuel portions provided the remaining 15 - 35% heat input. In order to obtain various in-furnace reburning zone stoichiometries (0.85 - 0.95), the reburning burners were operated at substoichiometric conditions. The balance of air was then introduced through OFA ports located in the upper furnace. Under optimized test conditions, reburning burner stability was observed during each of the reburn fuel test phases. No indication of excessive CO levels (at the stack) or burner instability was observed during any of the optimum test conditions.

The reburning burners were first adjusted for optimum NO_x emission levels via burner hardware. Changing the swirl component exiting the burner (via spin vanes in the outer zone) had an effect on resulting NO_x levels. Reducing the amount of swirl within this system provided more reburning fuel penetration and improved NO_x reduction capability. In addition, FGR could be introduced to the burner and an improvement in NO_x reduction was also observed under this condition. Over 50% NO_x reduction was achieved with natural gas, oil, and coal reburning at optimum conditions of natural gas, oil, and coal reburning burners. The optimum burner settings for each reburning fuel were determined based upon NO_x reduction capability, flame stability, and CO emission levels.

NO_x Emissions

A 40 - 75% NO_x reduction (from the baseline NO_x level) was achieved during reburning under various test conditions. These results are reported as overall reductions and consist of basically three components:

- NO_x reduction via lower heat input at the cyclone burner
- NO_x reduction via substitution of main combustion zone coal input with oil or natural

gas, thus reducing the total fuel nitrogen content to the furnace (oil and gas reburning tests only)

- NO_x destruction via the reburning process

The following results are based upon the overall NO_x reductions obtained.

Reburning Zone Stoichiometries. Figure 5 shows that NO_x emissions decreased with decreasing reburning zone stoichiometry for the three tested reburning fuels. The reburning burner throat stoichiometries were set at 0.4 for coal reburning and 0.2 for oil and natural gas reburning. Therefore, a greater portion of reburning fuel is required for coal reburning to achieve a given reburning zone stoichiometry. Varying the amount of natural gas and oil reburning fuels from 16 to 28% of total heat input changed the reburning zone stoichiometry from 0.95 to 0.85, respectively. To achieve the same reburning zone stoichiometry during coal reburning tests, 22 to 36% reburning coal had to be introduced to the furnace. Nitrogen-free natural gas provided the best NO_x reduction. NO_x concentrations ranged from 420 to 235 ppm while varying the reburning zone stoichiometry from 0.95 to 0.85 during gas reburning operation. From the baseline NO_x emission level of 925 ppm, these NO_x emission levels correspond to a 55 to 75% reduction. During No. 6 fuel oil reburning tests, NO_x reductions of 42 to 73% were achieved at reburning zone stoichiometries of 0.95 to 0.85. Pulverized coal reburning reduced the NO_x levels 40 to 68% for the same range of reburning zone stoichiometry. For 50% NO_x reduction from baseline conditions, 15% natural gas or 25% coal is required.

Flue Gas Recirculation. Figure 6 shows that NO_x emissions decreased with FGR rate to the reburning burners. In these tests, cyclone and reburning burner stoichiometries and fuel portions were constant. Reburning fuel portions were 22% for natural gas or oil reburning and 28% for coal reburning. As explained before, the reburning burner throat stoichiometry was set at 0.2 for gas and oil reburning and 0.4 for coal reburning. These reburning fuel portions provided the reburning zone stoichiometry of 0.9. Addition of FGR helps to improve the mixing between furnace combustion gases and the reburning fuel. With coal reburning, NO_x emissions were more sensitive to FGR than natural gas and oil reburning. This could be due to the presence of coal nitrogen in the reburning coal portions. Without FGR, some NO_x is being formed through the volatile flame attached to the reburning burner. When FGR is added, in addition to improved mixing, NO_x formation by the volatile reburning flame may be reduced. Therefore, coal reburning is more sensitive to FGR flow rate. This hypothesis will be confirmed through future investigations.

Cyclone Burner Stoichiometry. The effects of varying the cyclone burner stoichiometry and percent reburning fuel were investigated; the results are plotted in Figure 7. Although B&W recommends that minimal cyclone operation changes be employed, various cyclone stoichiometries were tested during this project in order to complete the technology database. Figure 7 is based upon maintaining a constant reburning zone stoichiometry of 0.9. As the cyclone stoichiometries were varied between 1.0 to 1.2, the percentage of reburning fuel to the reburning burners (versus coal to the cyclone to keep a constant 6-million Btu/hr load) was changed accordingly to achieve the reburning zone stoichiometry of 0.9. The natural gas input varied between 13 to 31%. The figure shows that NO_x levels decreased from 420 to 260 ppm as the cyclone stoichiometry was increased from 1.0 to 1.2, respectively.

During coal reburning tests as the cyclone stoichiometry increased from 1 to 1.2, 17 to 37% coal had to be introduced to achieve the reburning zone stoichiometry of 0.9. The NO_x levels were almost insensitive to the cyclone stoichiometry. During pilot-scale coal reburning tests, the same coal was utilized at the cyclone and reburning burners, but with different grind size. Since the total heat input was constant at 6-million Btu/hr, the total fuel nitrogen input to the furnace was not changed at different cyclone stoichiometries. These results indicate that the reburning zone stoichiometry is the controlling parameter in NO_x reduction in the reburning zone.

In-furnace NO_x measurements were taken throughout the SBS (nine sampling ports located on the side furnace wall) during both the baseline and reburning test phases. Baseline NO_x levels were uniform throughout the test facility, thus substantiating that all of the NO_x generation occurs within and/or immediately upon exiting the cyclone. Operating in the natural gas reburning mode (cyclone burner at 77% of load and 2% excess O_2; reburning burners input at 23% of load), NO_x levels at an elevation between the cyclone exit and the burners were 900, 743, and 450 ppm at the right side, left side, and center of the furnace, respectively. While the right-side/left-side NO_x levels agree with the baseline results, the 450 ppm at the center port indicates that some of the reburning fuel is being recirculated below the reburning burners. During coal reburning (cyclone burner at 72% load and 2% O_2; reburning burners at 28% load), NO_x levels of 900, 860, and 830 ppm were measured and recirculation was not observed. Measuring the NO_x levels directly above the reburning burners showed that the majority of NO_x reduction had occurred. These results substantiate that good mixing between the reburning fuel and combustion gases does exist.

Pilot Furnace Temperature Profile

SBS furnace temperatures were measured during both baseline and reburning phases to determine the technology's potential effect on temperature variations. Figure 8 illustrates the resulting FEGTs under various operating conditions. The data indicate that while utilizing reburning, rear-wall OFA ports, a cyclone stoichiometry of 1.1, zero percent FGR, and maintaining a constant 6-million Btu/hr furnace heat input, approximately a 50°F FEGT increase (from baseline) was observed. However, when 10% FGR was added to the reburning system, a temperature quenching phenomena occurred and a 50°F FEGT decrease (from baseline) resulted. A ± 50°F variation in FEGT is considered to have a minimal (if any) impact to boiler performance.

The in-furnace probing showed no significant temperature variations between the baseline/reburning conditions, except that again a quenching effect occurred in the reburning zone when FGR was added.

Combustible Loss

Unburned carbon and CO emissions were measured at both the stack and throughout the furnace during the baseline and reburning phases. An inherent cyclone characteristic is that the majority of the combustion occurs within the cyclone itself. Since the cyclone will continue to be operated in an excess air mode, this combustion characteristic will not be altered. However, the amount of unburned char that does not burn within the cyclone will now enter a reducing environment in the reburning zone, with the remaining combustion air not to be introduced until the OFA ports. When coal and fuel oil are used for reburning, additional unburned carbon may exist since the reburning fuels are introduced into the reducing environment of the reburning zone. Although they volatilize and partially burn, final burnout will be delayed until the burnout zone. If FGR is introduced, unburned combustible levels increase since the burnout zone residence time decreases due to increased mass loading through the furnace and the associated lower gas temperature profile whithin the reburn zone region. Efficient mixing of the air introduced through the OFA ports will help alleviate this concern and any potential CO emission problems.

Numerous measurements were taken to establish a database and to validate the trends of variation of unburned combustibles with different reburning zone parameters such as fuel split, FGR, and reburning fuel type. Table 5 illustrates the comparison of baseline and reburning tests at optimum conditions with and without FGR. Isokinetic samples of the fly ash were withdrawn from the stack of the SBS and analyzed for combustibles. In addition, total mass loadings of the fly ash were measured. Table 5 shows the carbon content of the fly ash and percentage of ash at the convection pass to the total ash input to the boiler at baseline conditions. During natural gas and oil reburning tests, the ash went down since these reburning fuels did not contain ash. On the other hand during coal reburning tests, ash loading almost doubled since ash from the reburning coal portion, unlike the cyclone, was not removed as slag. Total combustion efficiencies were calculated from ash percent in the convection pass, carbon content of the fly ash, and coal analysis. The overall change of combustion efficiencies from the baseline condition is less than 0.1% for natural gas and oil reburning and 0.13% for coal reburning. This is a minimal impact and provides a strong justification that the unburned combustible potential associated with the reburning technology could be controlled to acceptable levels.

Further analyses were performed to calculate the individual combustion efficiencies of cyclone and reburning fuels. It was assumed that natural gas burns completely. Therefore, the cyclone fuel burnout was calculated from the total combustion efficiency and fuel split during natural gas reburning tests. Knowing the cyclone fuel burnout, then reburning fuel burnout could be calculated during oil reburning and coal reburning tests. The results indicate that up to 99.79% of the coal reburning fuel was burned.

CO levels were low (less than 30 ppm) at the stack during the baseline tests and there was no apparent increase when the reburning technology was applied. In-furnace probing at the reburning zone revealed areas of high CO (>1000 ppm) due to the substoichiometric condition of this region. Upon introduction of OFA, the CO emissions were dramatically reduced – as stated above, less than 30 ppm CO was measured at the furnace exit. Thus, it is apparent that good mixing between the OFA and combustion gases did indeed exist.

Corrosion Potential

Since the reburning zone must be operated under substoichiometric conditions, corrosion potential within this region was investigated. By operating the cyclone in an excess air mode, the majority (if not all) of the sulfur from the coal in the main combustion zone is converted to SO_2. Due to the reducing atmosphere in the reburning zone, H_2S measurements were performed. High concentrations of H_2S can be conducive to increased rate of tube corrosion. H_2S concentrations at baseline and reburning conditions are illustrated in Table 6. Multiple measurements were performed in the furnace, and results are presented in a range of H_2S concentrations. Up to 60 ppm of H_2S were measured at the SBS during baseline conditions. H_2S levels did increase up to 90 ppm during gas reburning where no additional sulfur was added with the reburning fuel. Fuel oil utilized for reburning contained 0.78%

sulfur, and H_2S levels were compatible to those observed during gas reburning. When coal was utilized, however, up to 265 ppm of H_2S was measured. The impact of these levels of H_2S on tube wastage has yet to be determined. It is encouraging that only a small percentage of SO_2 from cyclone flue gases is converted to H_2S. In addition, when sulfur-bearing fuels were utilized for reburning, only a small fraction of the reburning fuel sulfur converted to H_2S. Up to 200 ppm of H_2S for oil reburning and 900 ppm of H_2S for coal reburning would be detected if all of the reburning fuel sulfur were converted to H_2S. Further evaluations will predict corrosion rates within the various furnace region during reburn operation.

FULL-SCALE UTILITY APPLICATION ECONOMICS

An economic analysis was performed in order to estimate the total capital and levelized revenue requirements for retrofitting and operating a reburning system to reduce NO_x emissions from a base case 200-MW unit. Costs associated with this process included: acquisition and handling of the reburning fuels, installation and operation of the reburning system, and boiler impacts and countermeasures. Prime concern within this task is to evaluate the potential of this technology on a commercial scale based upon dollar practicality. High priority exists concerning cost comparisons between utilizing various reburning fuels (gas, oil, or coal) in this process. The basis for the costs utilized in this evaluation are B&W cyclone reburning proposal cost estimates that have been prepared for numerous cyclone reburn proposed demonstration projects. These proposals have included utilizing each of the three reburn fuels.

The EPRI economic premises for electric power generating plants were used to estimate the above-stated objectives. The information reported herein is an expansion to a previous B&W/EPRI-sponsored engineering feasibility study that included an economic analysis (EPRI Project RP-1402-30). Table 7 summarizes the economic evaluation per each reburning fuel type.

The following listing summarizes the major equipment components utilized for each of the reburn fuels evaluated:

Major Reburning Control System Components

All Reburn Fuels

- Reburn Burners
- Overfire Air (OFA) Ports
- Tube Wall Openings/Replacement Wall Panels
- Piping/Ductwork to Reburn Burners/OFA Ports
- Burner/Combustion Control System
- Cyclone Gravimetric Feeders
- Cyclone Secondary Air Monitors

Coal Reburning

- Pulverizer/Gravimetric Feeder
- Coal Handling System

- Coal Silo
- Structural Steel/Pulverizer Enclosure

Oil Reburning
- Positive Displacement Pumps
- Oil Storage Tanks

Gas Reburning (where gas is currently not on-site)
- Gas Substation
- 10-Mile Tie-In to Nearest Pipeline at $300,000/Mile

Capital costs and 10-year levelized busbar power costs were sensitive to reburn fuel type, fraction, and price. Approximately 70 - 90% of the associated 10-year levelized cost is attributable to the fuel cost. Variations in prices for gas, oil, and coal in different demand regions will influence the economics of reburning with these alternative fuels. Prices (1987 dollars), ranging from \$2.50 - \$3.50/10^6 Btu for gas, \$3.00 - \$4.00/10^6 Btu for oil, and \$1.70/10^6 Btu for coal, were evaluated. Two gas availability scenarios were also considered – gas on-site and 10-mile tie-n to nearest pipeline at $300,000/mile.

The results presented in Table 7 give some indication of the variability in costs as key cost parameters are altered. For gas reburning, the installed capital costs range from $22.4/kW – if gas is available on-site – to about $44/kW – if the assumed $3 million gas-line cost is borne solely by the power plant. [Note: In many cases the gas supplier willextend gas service at no direct cost to the user, but will factor this cost into the contracted transportation charges (rate base). In this case, the capital cost would be the same as the gas on-site situation.]

The 10-year levelized costs for 15% gas reburning are shown to increase from 2.3 mills/kWh at \$2.50/10^6 Btu gas to 4.1 mills/kWh at \$3.50/10^6 Btu gas. These prices translate into gas-oil price differentials of \$0.80 and \$1.80/10^6 Btu, respectively. The gas reburning busbar costs do not include any credits for reduced coal handling/inventory, ash disposal, or maintenance as a result of 10% gas substitution.

Oil reburning is projected to cost about \$28/kW on the 200 MW plant with 10-year levelized costs ranging from 3.3 to 4.9 mills/kWh at assumed oil prices of \$3.00/10^6 Btu and \$4.00/10^6 Btu, respectively, and 19% oil firing.

Finally, capital costs for pulverized-coal reburning are estimated at $41.4/kW. Assuming the 25% reburn coal fraction is the same fuel as that currently fired in the cyclone burners, the 10-year incremental busbar cost is estimated at 1.7 mills/kWh.

CYCLONE REBURNING DEMONSTRATION

B&W is presently starting the final stage of its three-phase program to evaluate and commercially demonstrate reburning technology in cyclone-fired boilers. As stated earlier, Phase I involved an EPRI/B&W-sponsored engineering study, while Phase II was the pilot-scale testing performed at B&W's Alliance Research Center sponsored by EPRI/GRI/B&W and reported herein. Consequently, based upon the positive results of the first two phases, Phase III of the program is in progress and involves a full-scale demonstration of coal reburning at Wisconsin Power & Light's 100-MW_e Nelson Dewey Station Unit 2 (see Figure 9). The performance goals are to reduce existing uncontrolled NO_x emissions by greater than 50% and exhibit no serious impact on cyclone combustor operation, boiler efficiency, fireside corrosion or deposition, and ash removal system performance.

To accomplish these objectives, the project is divided into three phases:

Phase I - Design and Permitting
Phase II - Construction and Start-up
Phase III - Operation and Disposition

Each phase is broken down into tasks and subtasks as shown in the Work Breakdown Structure (WBS) shown in Figure 10. Project initiation is anticipated for Summer 1989 with system start-up in Fall 1991. An actual one year demonstration test duration is scheduled. The contract for this overall 43-month project is presently being negotiated under the DOE Clean Coal II solicitation. The program is being supported by the DOE, Wisconsin Power & Light, B&W, EPRI, the State of Illinois, and a consortium of utilities.

Wisconsin Power & Light's Nelson Dewey Unit 2 is a B&W single-wall-fired RB-type cyclone boiler equipped with three cyclone furnaces. The major components that will allow for the implementation of a coal reburning retrofit demonstration are:

1) Reburning burners capable of firing pulverized coal

2) Flue Gas Recirculation (FGR) to reburn burners

3) Dual-Air Zone Overfire Air (OFA) ports

4) Furnace wall tube panels for reburn burners/OFA ports

5) Air monitors, dampers, and damper drives within air/gas recirculation ducts and flues

6) Burners/OFA/FGR Control Management System

7) B&W MPS-67 Pulverizer with Gravimetric Feeder

8) Reburn fuel handling system

9) Gravimetric Feeders to replace Cyclone Volumetric Coal Feeders

10) B&W Continuous Monitoring Diagnostic System-140

11) Continuous Gaseous Emission Monitoring System

12) Miscellaneous equipment, wiring, piping and ducting, etc.

In summary, the demonstration project includes collecting baseline emissions and performance data, along with performing a general boiler system assessment, at Nelson Dewey Unit 2 prior to the coal reburning retrofit. The coal reburn system will be designed, fabricated, and installed based upon B&W's pilot-scale combustion tests, physical and numerical flow modeling, and experience/knowledge of full-scale burner/OFA port/control system retrofits. Parametric/optimization and performance tests will assess the potential of the technology from both the resulting emission reductions and boiler performance capability aspects. Finally, readiness for commercialization will be determined from both a technical and economic viewpoint.

CONCLUSIONS AND RECOMMENDATIONS

- A 40 - 75% overall NO_x emission reduction is achievable in cyclone-equipped units via the reburning technology. This overall NO_x reduction is attributed to three different mechanisms: 1) NO_x destruction in the reducing environment of the reburning zone via reburning process, 2) during gas and oil reburning, secondary fuel input to the reburning zone contributes a small percentage of NO_x formation (little or no fuel-bound nitrogen in fuel), and 3) reduced load and oxygen level at the cyclone. Typical uncontrolled NO_x emission levels from cyclone units are 600 - 1400 ppm at 3% O_2.

- For a 50% NO_x reduction, 15% natural gas or oil and 25% coal are required.

- The lower in-furnace reburning zone stoichiometry (0.85 - 0.95 range) provided the best overall NO_x reduction.

- Flue gas recirculation (FGR) to the reburning burners improved the mixing (turbulence) characteristics between the combustion gases/reburning fuel and consequently improved the NO_x reduction capabilities. FGR was more effective during coal reburning than during natural gas or oil reburning. Where applicable, this tool could be beneficial in future applications.

- CO emission levels were low (less than 30 ppm) throughout the various optimal test conditions and, thus, were of no concern during the reburning operation.

- Total combustion efficiency insignificantly decreased less than 0.1% for natural gas and oil reburning, and 0.13% for coal reburning. This is a minimal impact.

- Furnace exit gas temperatures (FEGTs) increased by less than 50°F during reburning operation.

- The cyclone itself must be operated under excess air conditions in order to minimize corrosion potential within the cyclone barrel. Accurate air/fuel control is also essential to alleviate this potential concern.

- H_2S concentrations in the reburning zone were 90 and 265 ppm for natural gas and coal reburning, respectively. Only a small portion of sulfur in the coal was converted to H_2S.

- The nominal costs to apply reburning to a baseloaded 200-MW cyclone unit to achieve a 50% NO_x reduction with different reburning fuels are estimated as follows (total capital costs, 10-year busbar power cost):

  - Gas (On-site or pipeline extension factored in rate base) – \$22.4/kW, 2.3 mills/kWh
  - Oil – \$28.4 kW, 3.3 mills/kWh
  - Coal – \$41.4/kW, 1.7 mills/kWh

  The corresponding gas and oil fuel price differentials (compared to coal) used to determine these values are \$0.80 and $\$1.30/10^6$ Btu, respectively. The coal reburn fuel is assumed to be the same as the main cyclone coal.

- If the capital cost of a 10-mile tie-in to an existing pipeline is passed on directly to this plant, the capital and 10-year levelized power costs increase to about \$44/kW and 3.1 mills/kWh, respectively.

- The reburning fuel choice has a major impact on the economics of this process. Site-specific consideration of the availability and price of alternative fuels, the availability of capital, and NO_x reduction target will influence the attractiveness of any one option.

ACKNOWLEDGMENTS

The authors extend their appreciation to the following B&W personnel for their help in the management and performance of the SBS testing: John Doyle, John Rackley, Cliff Eckhart, Mike Holmes, Suzanne Barnes, Vic Burgess, Gene Stoffer, John McCoury, and Terry Wilson.

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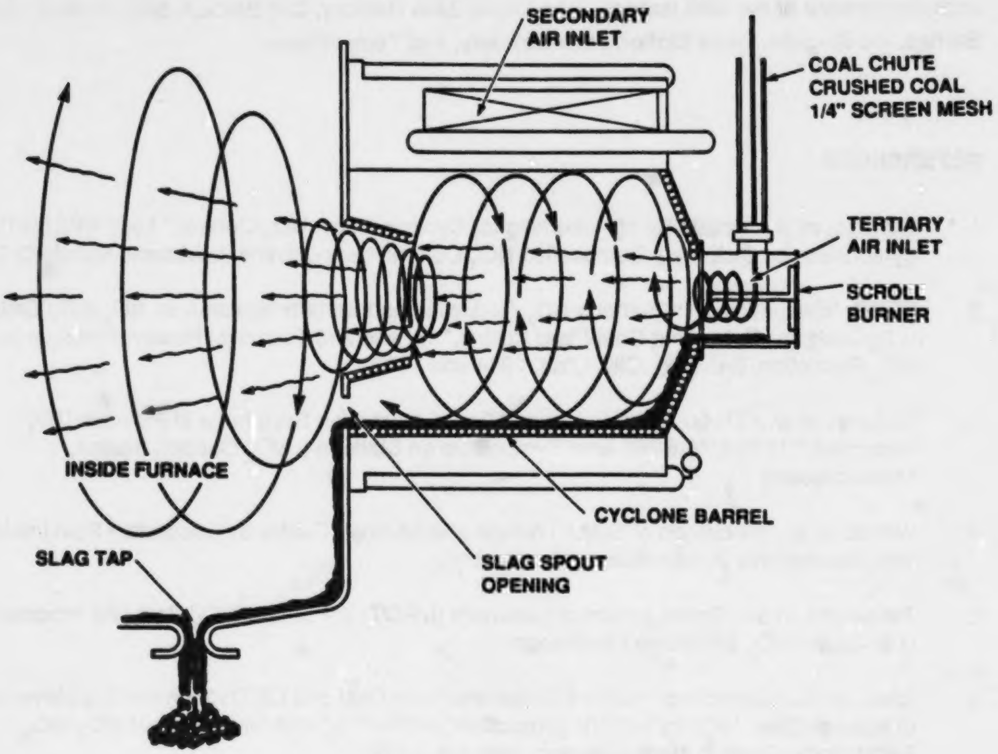
SECONDARY AIR INLET
COAL CHUTE CRUSHED COAL 1/4" SCREEN MESH
TERTIARY AIR INLET
SCROLL BURNER
INSIDE FURNACE
CYCLONE BARREL
SLAG TAP
SLAG SPOUT OPENING

Figure 1 Cyclone Furnace

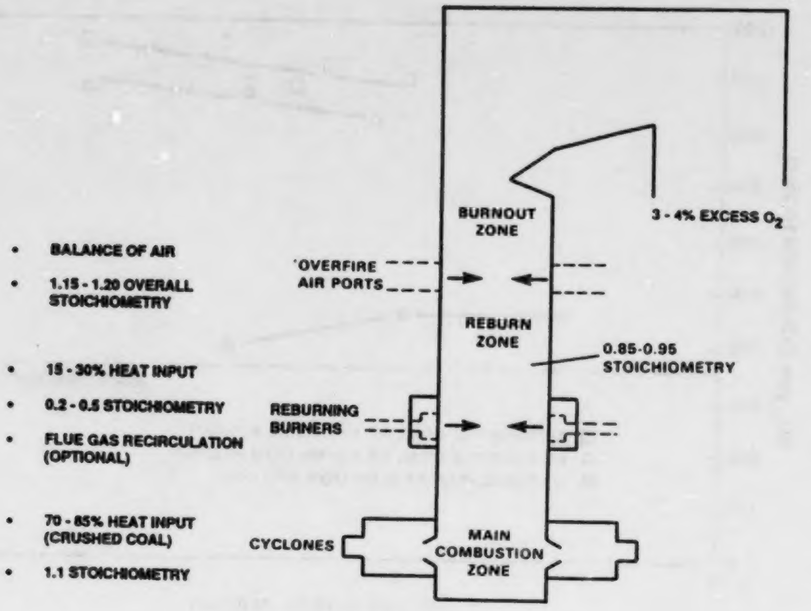
BALANCE OF AIR
1.15 - 1.20 OVERALL STOICHIOMETRY
15 - 30% HEAT INPUT
0.2 - 0.5 STOICHIOMETRY
FLUE GAS RECIRCULATION (OPTIONAL)
70 - 85% HEAT INPUT (CRUSHED COAL)
1.1 STOICHIOMETRY
BURNOUT ZONE
3 - 4% EXCESS O_2
OVERFIRE AIR PORTS
REBURN ZONE
0.85-0.95 STOICHIOMETRY
REBURNING BURNERS
CYCLONES
MAIN COMBUSTION ZONE

Figure 2 Reburning Technology

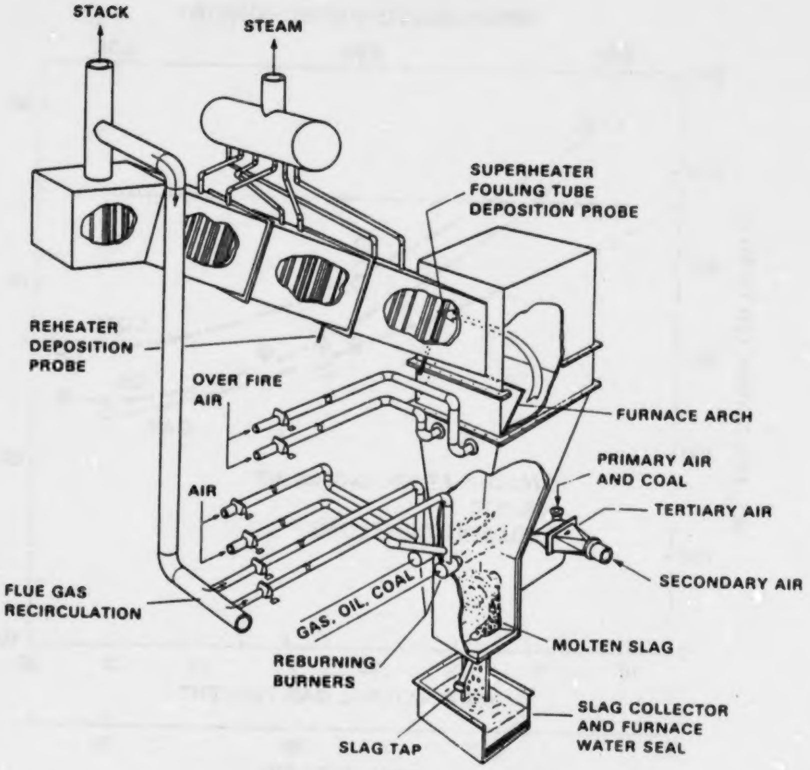
STACK
STEAM
SUPERHEATER FOULING TUBE DEPOSITION PROBE
REHEATER DEPOSITION PROBE
OVER FIRE AIR
FURNACE ARCH
PRIMARY AIR AND COAL
AIR
TERTIARY AIR
SECONDARY AIR
FLUE GAS RECIRCULATION
GAS, OIL, COAL
MOLTEN SLAG
REBURNING BURNERS
SLAG COLLECTOR AND FURNACE WATER SEAL
SLAG TAP

Figure 3 Small Boiler Simulator (SBS) Schematic

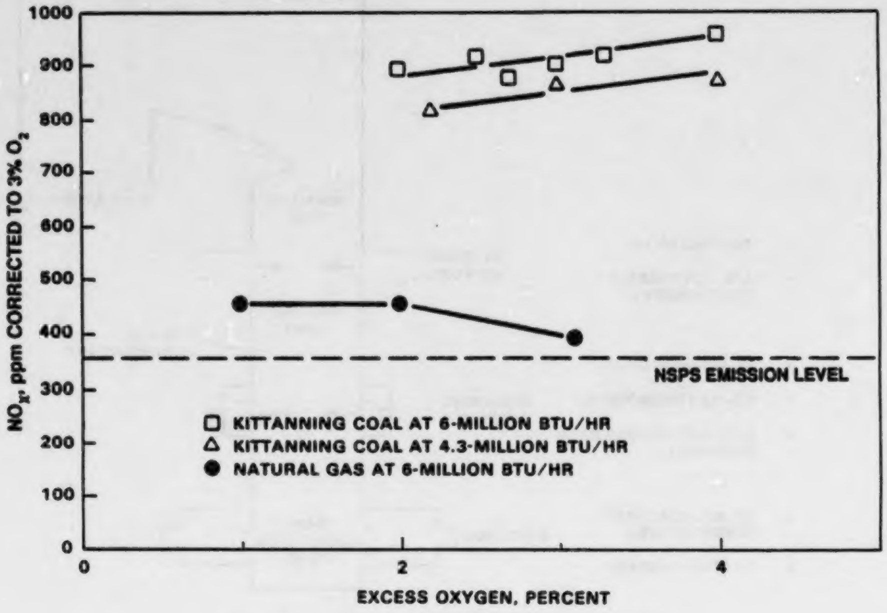

Figure 4 Baseline NO$_X$ Emission Levels in the SBS

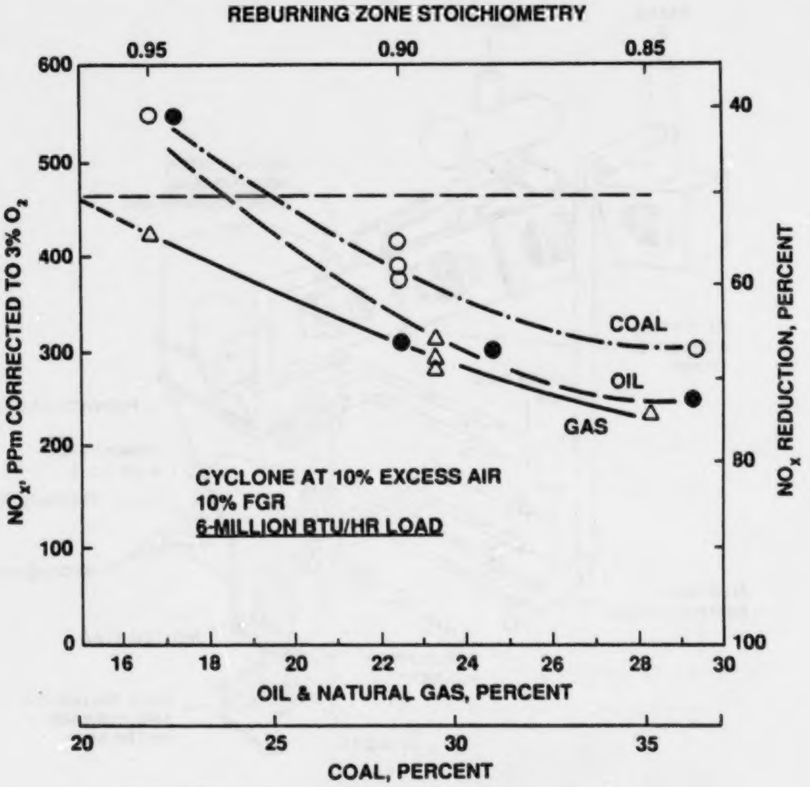

Figure 5 NO$_X$ Emission Levels With Reburning

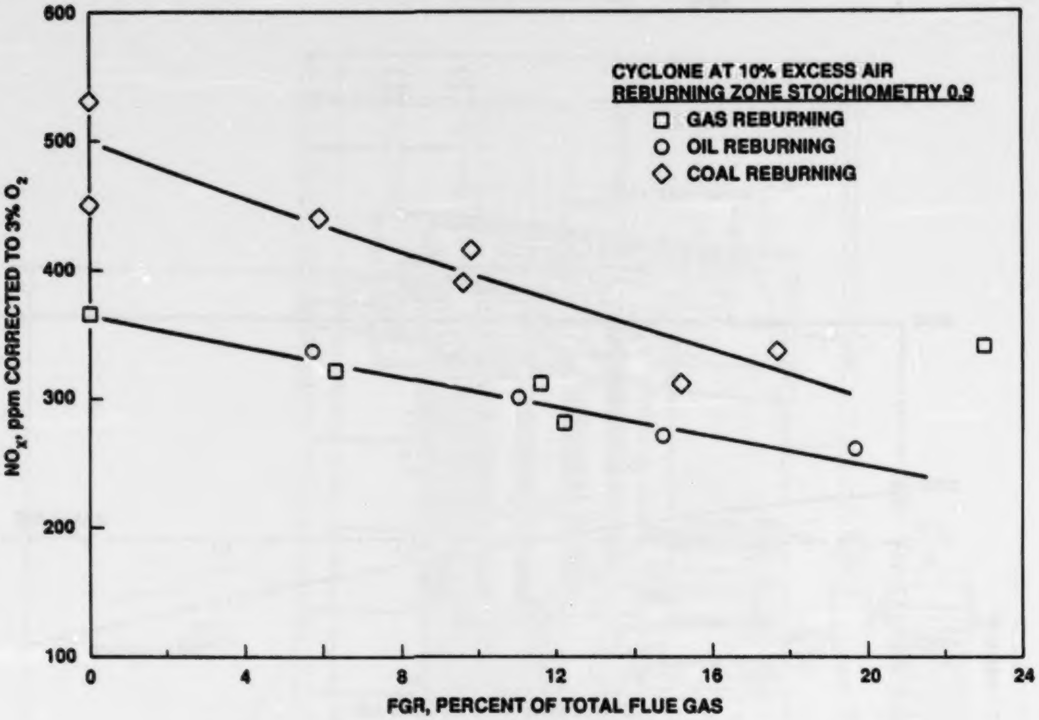

Figure 6 Effect of Flue Gas Recirculation (FGR) on NO$_X$ Emission Levels

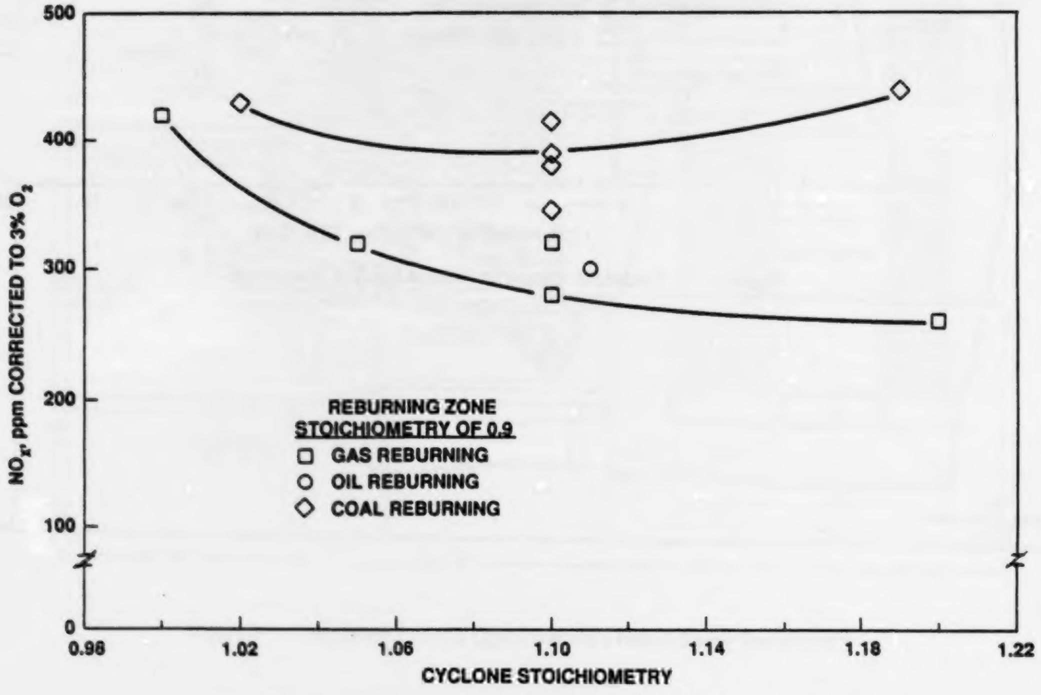

Figure 7 Effect of Cyclone Stoichiometry and Percent Reburning Fuel on NO$_X$ Emission Levels

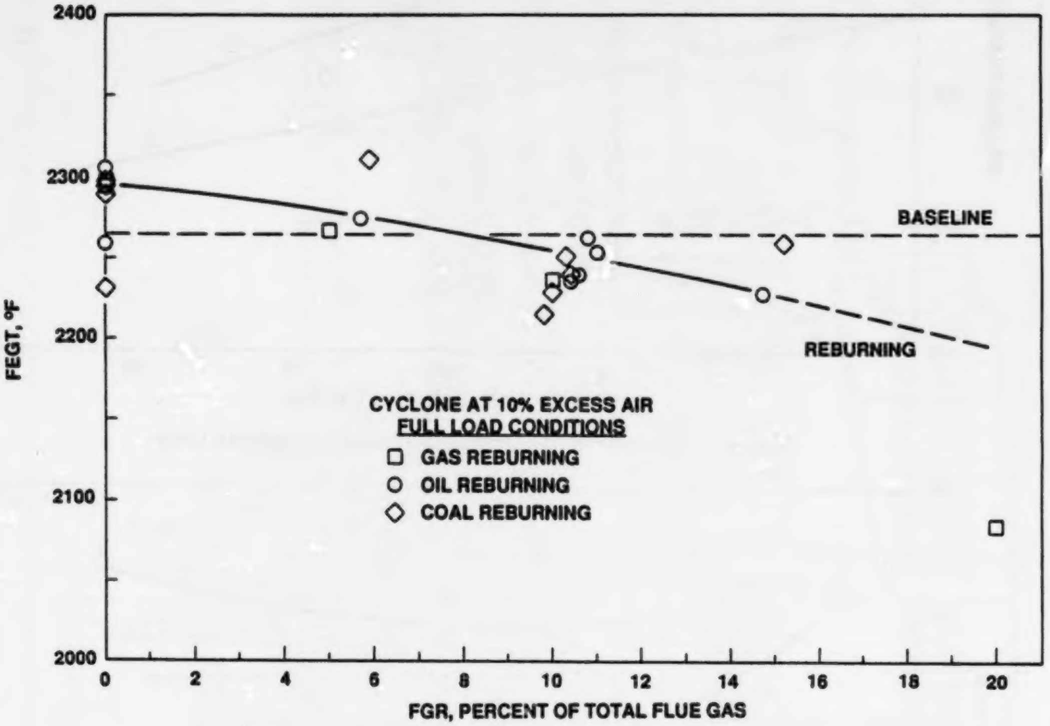

Figure 8 Operational Effects on Furnace Exit Gas Temperature (FEGT)

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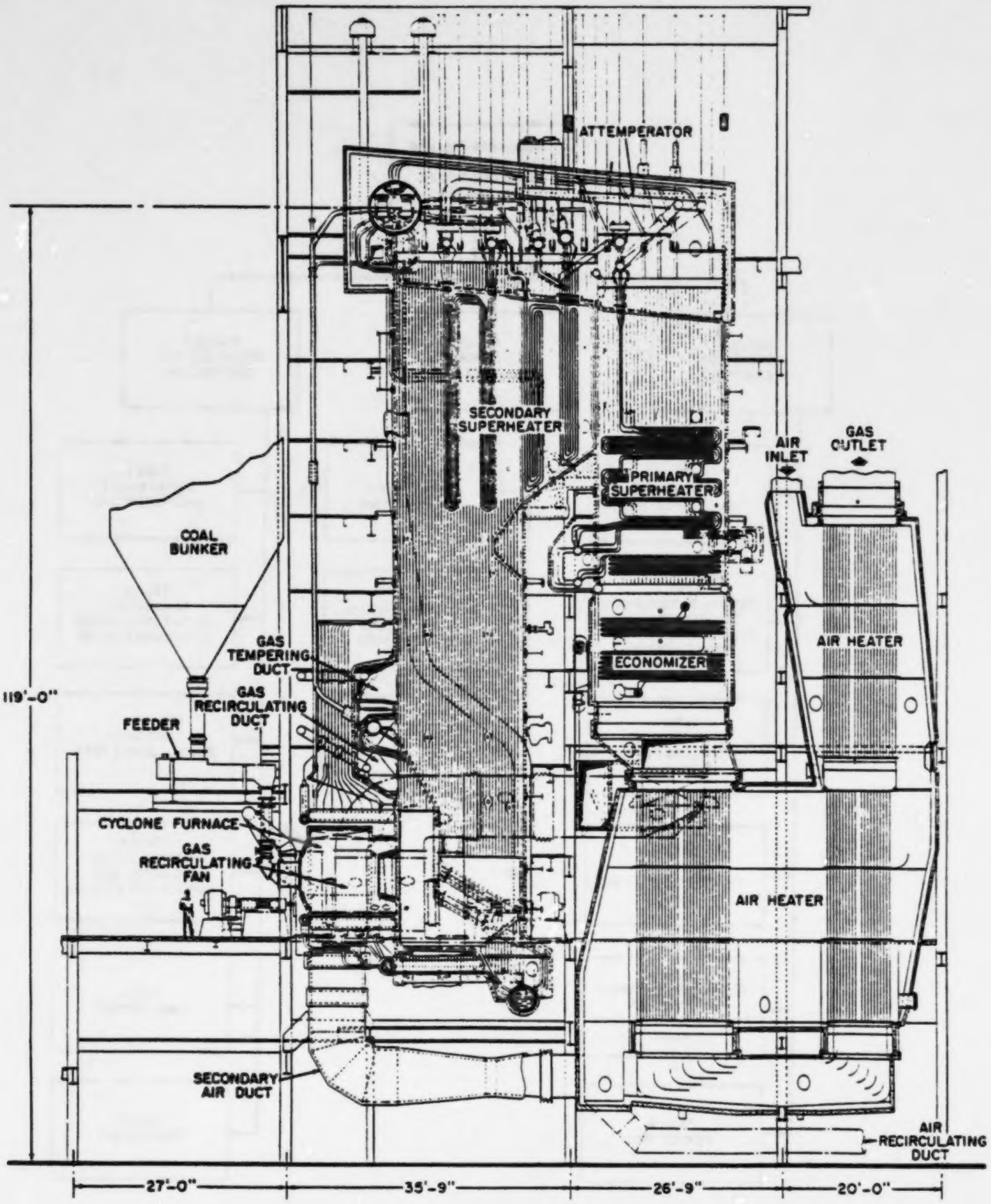
ATTEMPERATOR
SECONDARY SUPERHEATER
AIR INLET
GAS OUTLET
PRIMARY SUPERHEATER
COAL BUNKER
AIR HEATER
GAS TEMPERING DUCT
ECONOMIZER
GAS RECIRCULATING DUCT
119'-0"
FEEDER
CYCLONE FURNACE
GAS RECIRCULATING FAN
AIR HEATER
SECONDARY AIR DUCT
AIR RECIRCULATING DUCT
27'-0"
35'-9"
26'-9"
20'-0"

Figure 9 Wisconsin Power & Light Company's Nelson Dewey Station Unit 2

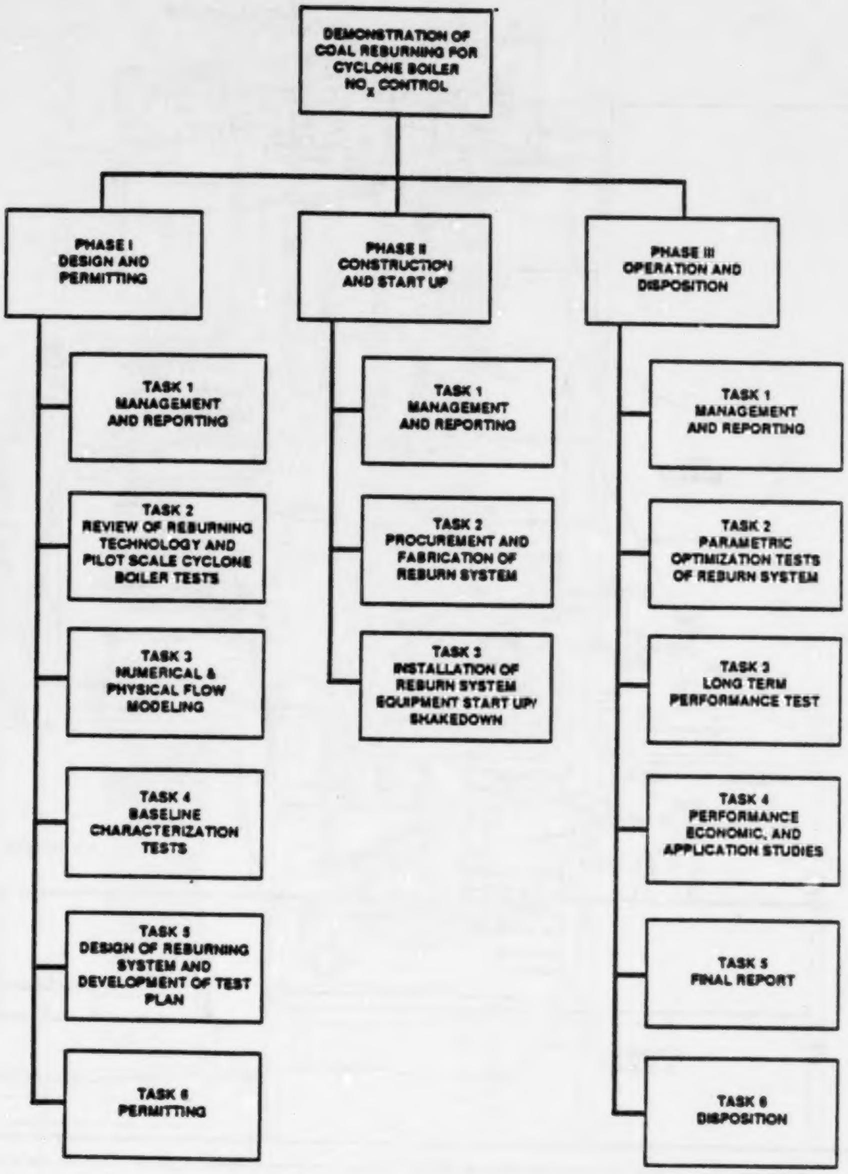
DEMONSTRATION OF COAL REBURNING FOR CYCLONE BOILER NO_x CONTROL
PHASE I DESIGN AND PERMITTING
PHASE II CONSTRUCTION AND START UP
PHASE III OPERATION AND DISPOSITION
TASK 1 MANAGEMENT AND REPORTING
TASK 2 REVIEW OF REBURNING TECHNOLOGY AND PILOT SCALE CYCLONE BOILER TESTS
TASK 3 NUMERICAL & PHYSICAL FLOW MODELING
TASK 4 BASELINE CHARACTERIZATION TESTS
TASK 5 DESIGN OF REBURNING SYSTEM AND DEVELOPMENT OF TEST PLAN
TASK 6 PERMITTING
TASK 1 MANAGEMENT AND REPORTING
TASK 2 PROCUREMENT AND FABRICATION OF REBURN SYSTEM
TASK 3 INSTALLATION OF REBURN SYSTEM EQUIPMENT START UP/ SHAKEDOWN
TASK 1 MANAGEMENT AND REPORTING
TASK 2 PARAMETRIC OPTIMIZATION TESTS OF REBURN SYSTEM
TASK 3 LONG TERM PERFORMANCE TEST
TASK 4 PERFORMANCE ECONOMIC, AND APPLICATION STUDIES
TASK 5 FINAL REPORT
TASK 6 DISPOSITION

Figure 10 Project Work Breakdown Structure

Table 1

NO_x EMISSIONS WITH IN-FURNACE NO_x REDUCTION

Main Fuel/Reburning Fuel	NO_x Level (ppm @ 3% O_2)
Natural Gas/Natural Gas	15 - 40
Fuel Oil/Fuel Oil	40 - 60
Pulverized Coal/Pulverized Coal	50 - 100
- - - - - - - -	
Future Cyclone Application	240 - 560*

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* Based on a 60% NO_x reduction from existing cyclone emission levels.

Table 2

SUMMARY OF REBURNING CONDITIONS EVALUATED DURING PILOT TESTS

	Main Combustion (Primary) Zone	Reburning Zone	Burnout Zone
Fuel	Kittanning Coal	Natural Gas, No. 6 Fuel Oil, Kittanning Coal	---
Fuel Split	70 - 85%	15 - 30%	---
Stoichiometry	1.0 - 1.2	0.85 - 0.95	1.05 - 1.2
Residence Time (Assume Plug Flow)	0.1 second	0.5 - 0.8 second	0.6 - 0.9 second

Table 3

COMPARISON OF BASELINE CONDITIONS FOR SBS FACILITY AND COMMERCIAL UNITS

	SBS	Typical Cyclone-Fired Boilers
Cyclone Temperature	>3000°F	>3000°F
Residence Time	1.4 sec at full load	0.7 - 2 sec
Furnace Exit Gas Temperature	2265°F	2200° - 2350°F
NO_x Level	900 - 1200 ppm	600 - 1400 ppm
Ash Retention	80 - 85%	60 - 80%
Unburned Carbon	<1% in ash	1 - 20%
Ash Particle Size (MMD; Bahco)	6 - 8 microns	6 - 11 microns

Table 4

FUEL ANALYSIS

	Kittanning Seam 2		Fuel Oil
	As-Received	Dry	
Proximate Analysis, %			
Moisture	5.62	---	---
Volatile Matter	35.35	37.45	---
Fixed Carbon	49.31	52.25	---
Ash	9.72	10.30	---
Gross Heating Value, Btu per lb	12,580	13,330	18,509
Btu per lb (M&A Free)	---	14,860	---
Ultimate Analysis, %			
Moisture	5.62	---	---
Carbon	69.93	74.09	88.25
Hydrogen	4.77	5.05	10.70
Nitrogen	1.42	1.50	0.22
Sulfur	2.55	2.70	0.78
Ash	9.72	10.30	0.05
Oxygen (Difference)	5.99	6.36	0.00
Total	100.00	100.00	100.00

Natural Gas:
88.27% methane, 5.27% ethane, 1.72% propane, 3.6% nitrogen, 1.14% others

Table 5

COMPARISON OF COMBUSTION EFFICIENCIES

	CARBON, %	ASH, % IN CONVECTION PASS	TOTAL COMBUSTION EFFICIENCY	CYCLONE FUEL BURNOUT, %	REBURNING FUEL BURNOUT, %
BASELINE	0.3	18.2	99.99	99.99	N/A
GAS REBURN					
NO FGR	2.3	14.2	99.96	99.95	100
10% FGR	4.5	14.2	99.92	99.90	100
OIL REBURN					
NO FGR	3.0	14.2	99.95	99.95	99.95
10% FGR	5.4	14.2	99.91	99.90	99.93
COAL REBURN					
NO FGR	1.6	32.7	99.94	99.95	99.91
10% FGR	3.4	32.7	99.87	99.90	99.79

Table 6

REBURNING NO_X CONTROL FOR CYCLONE BOILERS FIRESIDE CORROSION - H_2S CONCENTRATION (ppm)

MEASURED	BASELINE	GAS REBURN	OIL REBURN	COAL REBURN
CYCLONE OUTLET	0	—	—	98
BELOW REBURN	40-55	50	0	0-200
REBURN ZONE	0-60	25-90	14-93	0-265

Table 7

ECONOMIC EVALUATION FOR APPLYING REBURNING TO CYCLONE BOILERS*

REBURNING FUEL	FUEL COST ($/$10^6$ Btu)	MAIN/REBURN FUEL SPLIT	TOTAL ESTIMATED CAPITAL COST REQUIRED ($/kW)	10-YEAR LEVELIZED BUSBAR POWER COST (mills/kWh)
GAS	2.5	85/15	22.4	2.3
	3.5	85/15	22.5	4.1
	2.5	85/15	43.9**	3.1**
	3.5	85/15	44.1**	4.9**
OIL	3.0	81/19	28.4	3.3
	4.0	81/19	28.6	4.9
COAL (SAME AS MAIN FUEL	1.7	75/25	41.4	1.7

---

* BASED ON 200-MW UNIT OPERATING AT 65% CAPACITY WITH 50% REDUCTION. CYCLONE BURNER OPERATES AIR-RICH (1.1 STOICHIOMETRY) AND REBURN ZONE FUEL-RICH (0.93 - 0.97 STOICHIOMETRY).

** ASSUMES $3-MILLION GAS PIPELINE COST.

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Application of Reburning to a Cyclone Fired Boiler

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This paper has been reviewed in accordance with the U.S. Environmental Protection Agency's peer and administrative review policies and approved for presentation and publication.

ABSTRACT

Cyclone fired units typically produce the highest nitrogen oxide (NO_x) emissions of the commonly employed boiler designs. Although cyclone units represent about 14% of the pre-new source performance standards (NSPS) coal fired generating capacity, they contribute about 21% of the NO_x emitted by pre-NSPS units. Reburning is currently viewed as the most promising in-furnace NO_x reduction combustion technology for cyclone fired boilers. Based on the above the U.S. EPA, Electric Power Research Institute, Gas Research Institute, and Ohio Coal Development Office have cosponsored Combustion Engineering's demonstration of reburning on a large cyclone fired boiler. Key elements of the program include reburn system design and retrofit, followed by short and long term test segments, and an overall economic evaluation of reburning applicability. Coal is the primary boiler fuel and natural gas will be used as the reburn fuel.

The paper reports the progress principally of the design related phases of the program. Reburn system design criteria are presented as well as the methodology and results of the cold-flow modeling evaluation which was used to identify existing boiler aerodynamics and help to determine the optimum configuration for reburn fuel and additional air injectors. Mathematical modeling was conducted to determine potential effects of a reburn system on boiler thermal performance. Finally, experience has been cited regarding effects of low air/fuel stoichiometric conditions on boiler tube wastage.

INTRODUCTION

Statement of the Problem

It is widely acknowledged that NO_x plays an important role in the formation of acid rain (1,2,3). One important source of NO_x is utility boilers, particularly those which burn coal and to a lesser extent those which fire oil or natural gas. Of particular interest are coal fired cyclone boilers since they contribute 21% of the NO_x emitted by pre-NSPS coal fired units even though they represent only 14% of the pre-NSPS coal fired generating capacity. In-furnace NO_x reduction technologies represent one commercially attractive means for reducing NO_x. Reburning represents a particular in-furnace NO_x reduction technique for which cyclone fired boilers are uniquely well suited.

Given this background the U.S. EPA, Gas Research Institute (GRI), Electric Power Research Institute (EPRI), and the Ohio Coal Development Office (OCDO) have sponsored a program for Combustion Engineering (C-E) to demonstrate reburning on a cyclone fired boiler. The Consolidated Natural Gas Company (CNG) is a significant contributor to the program as natural gas will be utilized as the reburn fuel. Ohio Edison is a key participant in the program and will be providing Unit No. 1 at their Niles Station, a 108 MW cyclone fired boiler, as the demonstration site. Working with C-E as subcontractors in this program are Energy Systems Associates (ESA), Mitsubishi Heavy Industries (MHI), and Physical Sciences, Incorporated (PSI).

Program Objective

The overall objective of this program is to successfully demonstrate the operation of a reburn system on a cyclone fired boiler. Figure 1 shows the key tasks in the program and a schedule for their planned implementation. Progress to date includes completion of the technology review task and most of the reburn system design task. Current activities are mainly centered on the reburn system fabrication and installation task. This paper will serve as a foundation for future technical papers while specifically reporting on the progress made within Tasks 1 and 3 (See Figure 1). In this regard it will present important criteria to be considered in the design of a reburn system, it will report on the use of cold-flow modeling as a site specific engineering design tool, and it will address the question of potential impacts of reburn system operation on boiler performance.

Reburn Technology

The concept of reburning and the postulated chemical reactions which account for the reduction of NO_x in the reburn zone have been addressed elsewhere in the literature (4,5,6,7) and will not be reiterated in detail here. Briefly, reburning is an in-furnace technique for reducing NO_x by creating a slightly reducing zone downstream of the primary combustor as shown schematically in Figure 2. The reducing zone is created by introducing fuel into a zone with insufficient oxygen available to fully combust the fuel. The presence of a reducing zone creates intermediate nitrogen-containing species which subsequently react with previously formed NO_x to form the desired product, molecular nitrogen. Any unburned fuel leaving the reburn zone is subsequently burned to completion in the burnout zone.

Reburning can be used on all types of fossil fuel fired boilers (i.e., wall, tangential, and cyclone) and, in fact, has been successfully employed on a number of oil fired boilers in Japan where oil has been used as the reburn fuel (8). Wall fired and tangentially fired boilers employ more conventional burners (as contrasted to a cyclone boiler) making possible the opportunity for other in-furnace NO_x reduction technologies involving burner modifications in conjunction with staged air combustion. Since a cyclone combustor may not be able to tolerate significant changes to its operation, such as lower excess air, without the possibility for creating other problems, it is limited to an in-furnace NO_x reduction technology that does not depend on significant changes to its present mode of operation. Reburning does not require that any significant operational changes be made to the primary combustor. The key requirement is that the fuel feed rate be reduced in the primary combustor with an equivalent amount (on a Btu basis) of fuel being injected in the reburn zone, usually not more than 20% of the total fuel input. The excess air, and hence the air/fuel stoichiometry within the cyclone combustors, can be held constant thereby not creating the potential for cyclone operational problems.

REBURN SYSTEM DESIGN

Technical Review

A successful reburn system should meet the theoretical criteria for effective NO_x reduction, it should not adversely affect normal boiler operation, and it should be competitively economical to install and operate.

The reburn system being designed for Ohio Edison's Niles Station, Unit 1, will fire natural gas as the primary reburn fuel, but the reburn fuel injectors have been designed to accommodate oil as a future reburn fuel. The reburn fuel feed system is designed for a nominal fuel flow rate of 20% of total fuel fired (on a heat input basis). Recirculated flue gas will be used as a carrier to inject fuel into the reburn zone; the recirculated flue gas injection system will be designed for a nominal flow rate of 10% of flue gas flow leaving the stack. The system for injection of additional air downstream of the reburn zone will be nominally designed for an air flow rate that will permit original overall boiler stoichiometric conditions to be maintained. Note that the stoichiometry within the cyclone combustor will not be altered from normal operating conditions. Parametric testing will be carried out under Task 5 to determine optimum flow rates of reburn fuel and recirculated flue gas as well as optimizing other reburn system operational parameters for effective NO_x reduction.

Overall design objectives for the reburn system were:

(1) To meet theoretical criteria for effective NO_x reduction while minimizing any impact on normal boiler operation.

(2) To incorporate operational flexibility within the design to permit optimized field performance

The goal of Task 1 in the program was to develop a list of key design criteria commensurate with the overall design objectives for the reburn system. The criteria would consist of theoretical criteria for effective NO_x reduction and they would identify key practical, commercial considerations for reburn system design, installation, and operation.

Key design criteria for the reburn zone were determined to be:

- Inject reburn fuel into as high a temperature zone as possible
- Maintain average stoichiometry between 0.90 and 0.95
- Permit a small amount of O_2 to promote formation of OH and H radicals
- Maintain a residence time between 0.5 and 0.7 seconds
- Maximize entrainment, mixing, and dispersion of reburn fuel
- Avoid direct fuel impingement on boiler walls
- Minimize the number of required boiler penetrations
- Locate fuel injection nozzles to minimize boiler/structural steel modifications
- Provide for maximum flexibility of reburn fuel jet direction and flow rates
- Provide a fuel flow rate control system with automatic load following capability
- Provide safeguards for fail-safe operation

The first five criteria, above, deal with theoretical considerations while the last six deal with practical, commercial considerations.

Injection of reburn fuel into a high temperature zone enhances NO_x reduction by favoring higher chemical reaction rates; however, reburn fuel should not be injected before the bulk of the primary fuel has burned to completion. If injected too early in a coal fired boiler, natural gas, as the reburn fuel, would preferentially burn before the coal char particles have burned to completion. This could increase the possibility for unburned carbon while, additionally, not permitting all the char bound nitrogen to be released prior to the reburn zone. A stoichiometry in the range of 0.90 to 0.95 has been found to represent a reasonable balance between achieving a desirable stoichiometry from the standpoint of NO_x reduction chemistry and a stoichiometry that will not exacerbate ash deposition and/or boiler tube wastage (8). Though the reaction kinetics for NO_x reduction in the reburn zone are quite fast, requiring on the order of 0.1 second, the bulk of the residence time in the reburn zone is required to achieve good mixing of the reburn fuel with the bulk flue gas. The naturally occurring small amounts of oxygen in the bulk flue gas entering the reburn zone, along with that in the recirculated flue gas which is used to carry and mix the natural gas, are sufficient to promote the desired formation of OH and H radicals. Effective and rapid mixing of reburn fuel ensures that all NO_x entering the reburn zone will contact the intermediate nitrogen-containing species so that maximum NO_x reduction is possible. Effective mixing must be achieved in such a way that there is no direct fuel impingement on boiler walls which could exacerbate tube wastage or iron-related ash deposition by creating low local stoichiometries or worse yet a condition where extremes occur between highly oxidizing and highly reducing atmospheres. Other practical considerations involve minimizing the number of boiler penetrations and the avoidance of unnecessarily costly boiler modifications relative to the number and placement of reburn fuel injectors. The number and placement of reburn fuel injectors must not create thermal or structural boiler problems. The reburn fuel injection system should have sufficient flexibility to permit on line adjustment to maintain optimum mixing as a function of boiler operational variables, such as load changes, that could alter gas flow patterns within the reburn zone. Since the amount of reburn fuel required will likely change as a function of boiler load, a control system should be provided which will provide automatic load following capability. The reburn fuel control system should also have permissives which must be satisfied to ensure its safe operation.

Key design criteria for the burnout zone were determined to be:

- Inject burnout air in as low a temperature zone as possible commensurate with obtaining fuel burnout before entering the first convective surface.
- Provide for rapid mixing of air to minimize pockets of unburned fuel.
- Avoid direct air impingement on furnace walls.
- Minimize final excess oxygen commensurate with obtaining good fuel burnout.
- Provide for a residence time in the range of 0.6 to 0.8 second.
- Minimize the number of required boiler penetrations commensurate with obtaining good mixing.
- Locate burnout air injectors to minimize boiler structural modifications while providing good mixing.
- Provide for maximum flexibility of air jet direction and flow.
- Provide an air flow rate control system with automatic load following capability.
- Provide safeguards for fail-safe operation.

For the burnout zone, unlike the reburn zone, air should be injected in as low a temperature gas as possible to prevent the reformation of NO_x. However, lower temperatures could prevent complete burnout of the uncombusted fuel which leaves the reburn zone, and a balance must be struck between the dual objectives of minimizing NO_x reformation and complete combustible burnout. Rapid and thorough mixing in the burnout zone is necessary. Although the reaction between fuel and oxygen is quite rapid, the bulk of the recommended 0.6 - 0.8 second residence time is needed to achieve effective mixing rather than for combustion reaction time per se. Direct impingement of air on furnace walls should be avoided, more for reasons of preventing local temperature increases than for any concern about the presence of an oxidizing atmosphere. The amount of air should be just sufficient to achieve desired fuel burnout; an overabundance of excess air will contribute to dry gas losses and will increase the potential for NO_x reformation in the burnout zone. The rationale for employment of the practically oriented burnout zone design criteria is basically the same as that presented earlier for the reburn zone.

Cold-Flow Modeling

As previously discussed, the aerodynamically controlled mixing processes of the injected reburn fuel (hereafter designated as UFI for Upper Fuel Injector) in the reburning zone and the air (hereafter designated as AA for Additional Air) in the burnout zone are major factors in determining the effectiveness of NO_x reduction in a reburn system. Since the penetration and dispersion of the UFI and AA jets are a function of the gas flow patterns in the furnace, the injection process must be characterized in terms of both injector and furnace operating parameters for the boiler in question.

Based on established methods for physical flow modeling (9), the purpose of the isothermal flow modeling program was to develop and screen UFI and AA injection concepts which would provide effective penetration and mixing within Ohio Edison's Niles Station Unit 1. Key components of the cold-flow modeling experimental program included:

- Fabrication of a one-ninth scale isothermal flow model of Niles Unit 1.
- Characterization of the baseline furnace aerodynamics entering the reburn zone, within the reburn zone, and within the burnout zone.
- Characterization of the UFI and AA injection process as a function of furnace load; UFI and AA injector size, number, and location; and injection tilt, angle, and velocity.
- Identification of UFI and AA injection configurations for subsequent design, fabrication, and installation.

Experimental Test Program

The isothermal flow modeling was performed at C-E's Kreisinger Development Laboratory. The one-ninth scale model of the Niles Unit, Figure 3, was built primarily of clear plastic, encompassing the entire furnace from the cyclone combustors to the vertical furnace outlet plane. The cyclone combustors were designed to produce the correct swirl number and momentum (axial and tangential) entering the primary furnace. Upper furnace radiant and convective heat transfer surfaces were also modeled. A header system fed by a high pressure blower controlled the introduction of smoke or tracer gas to any one or a combination of UFI or AA injection nozzles. Flue gas flow through the model was simulated by drawing air through it with a large induced draft fan.

An initial series of isothermal flow modeling tests characterized the as-found or baseline gas flow characteristics of the boiler. Following the establishment of the baseline reference data, flow modeling of the reburn system consisted of two screening level tests for both the UFI and AA jets:

- Screening Level 1 - Flow visualization (with smoke) of a large number of reburn fuel/burnout air injector configurations.
- Screening Level 2 - Mixing study tests on best configuration candidates from Level 1.
- Level 3 - Detailed three-dimensional velocity flow modeling on best configuration candidates from Level 2.

In Screening Level 1, smoke flow visualization tests were performed for each candidate injection system at simulated full and 70% load furnace operating conditions. Each injection configuration was evaluated at three injection velocities, three tilts, and a number of yaws. After initial selection of the best injection configurations, Screening Level 2 testing was performed consisting of methane tracer gas injection with concentration measured with a laser absorption spectrophotometer. Final injection configurations were determined from results of detailed velocity profile measurements using three dimensional (five-hole pitot tube) analysis techniques. Details of the instrumentation used to carry out these measurements are given in Reference 9.

Test Results

Baseline furnace velocity fields were measured and the flow patterns determined at the five test planes shown in Figure 4. These data were obtained under flow conditions simulating boiler operation at 100% and 70% MCR (Maximum Continuous Rating). The data were then used to formulate potential injection configurations for the UFI and AA systems. For example, Figure 5 shows the results for a zone of particular interest, the entrance to the reburn zone. As shown, this plane is characterized by two high velocity areas along the rear wall of the boiler, corresponding to the flow originating from the two lower (of four) cyclones. The outlet from the lower cyclones is partly below the dividing wall; consequently, a large portion of the gases exiting these cyclones passes unimpeded under the division wall into the secondary furnace.

Fourteen UFI configurations were evaluated at three different yaws in the first reburn fuel injector screening test series. Based on the results from these tests it was found that, at all velocities tested, three injectors along the rear wall were insufficient to cover the flow plane. Five injectors along the rear wall were found to be the best overall. However, with this configuration, the two outermost injectors suffered from jet wall attachment when injecting straight into the furnace. Yawing these injectors toward the center of the unit eliminated this problem. Injection from the side wall also provided generally good distributions, but no better than with the more economical five rear wall injector configurations.

The addition of pant-legs to the ends of the injection nozzles was found to be an effective means of enhancing the dispersion of the reburn fuel jets. Pant-legs were found to significantly improve the dispersion of the jet near the rear wall. The most effective use of yawing was when each of the three inboard upper nozzles was split and yawed, using pant-legs, while the lower nozzles were unencumbered and allowed to penetrate to near the division wall. Since it would not make sense to put pant-legs on the outermost sets of injection nozzles (being located next to the side walls), these nozzles, both upper and lower, were yawed toward the center of the furnace.

Based on the results from Screening Level 1, the Screening Level 2 test matrix for the reburn fuel injectors was developed. The mixing studies carried out in the Screening Level 2 tests supported most of the conclusions from the initial smoke flow visualization studies and permitted the selection of an optimum UFI jet configuration. At this point it was determined that the penetration and dispersion performance of the injectors was a function of the flow field into which they were injected. Injectors that were firing into the lower velocity segments along the rear wall of the furnace at a simulated velocity of 100 ft/sec (30 m/sec) were capable of penetrating all the way to the division wall, while those that injected into the higher velocity zones, associated with the two lower cyclones, could not. It was found that an injection velocity of 300 ft/sec (91 m/sec) was too high, resulting in jet impaction on the division wall almost directly across from the point of injection. Reducing the recirculated flue gas flow rate below 10% generally resulted in reduced levels of dispersion. It was found that tilting the nozzles down improved the overall dispersion of the jet at the outlet of the reburn zone, while tilting upward reduced the dispersion. The configuration depicted in Figure 6 was chosen as the recommended UFI configuration.

In determining the location of the air injector jets in the burnout zone, the potential for injection sites was limited to the side walls and one centrally located on the front wall because of interferences on the front wall of the unit. The choice of candidate AA injection configurations/locations was also guided by the need to inject air into a zone which contained numerous internal boiler obstructions in the form of cyclone burner hanger tubes. Figure 7 shows the location of the AA injectors evaluated.

Each AA configuration was evaluated at 150 and 300 ft/sec (45.7 and 91.4 m/sec), three tilts (-20°, 0°, +20°), and configuration specific yaws ranging between plus and minus 20°. During all AA injection tests the recommended UFI injection configuration was installed on the model and was in service.

From the smoke flow visualization tests it was clear that the injection trends were consistent with those of the UFI injection system tests; i.e., the jet penetration and dispersion increased as the AA jets were tilted into the flow and yawed for maximum dispersion.

Although air injection from Locations I, A, and B (Figure 7) provided reasonable dispersion to the central regions of the burnout zone, the overall dispersion was no better than the combination of A and B alone. Location I was eliminated because the difficulty of installation would not be justified by its performance.

The recommended AA configurations (Locations A and B on each side of the unit) are depicted in Figure 8. Each injector is divided into three compartments: the upper two are designed to yaw from straight-ahead to an extreme of a 40° included angle, and the bottom compartment can yaw plus or minus 10°. All compartments can tilt in unison plus or minus 25° from horizontal.

Injection from Locations C and F resulted in jet attachment along the rear wall with poor dispersion. Down tilting (into the bulk gas flow) from any given location usually provided better mixing, but extreme downward tilting could cause undesirable recirculation of air into the reburn zone. Injection from the remainder of the locations (D, G, H, E) did not result in better dispersion and had the further disadvantage of a lower residence time within which to attain complete mixing.

Following selection of the recommended UFI configuration and the recommended AA configuration, the combination of these integrated configurations was then subjected to steady state gas mixing studies at 70% and 100% loads and to complete three-dimensional flow velocity characterization tests. The results from these tests were then used to assess the impact of the reburn system on original baseline furnace aerodynamics.

IMPACTS OF REBURN SYSTEM ON BOILER PERFORMANCE

Boiler Thermal Performance

Since operation of a reburn system requires that the main fuel be reduced by up to 20% of its original value and that an equivalent amount of reburn fuel be injected downstream with recirculated flue gas as a carrier, it is reasonable to expect that some changes will occur in boiler gas and steam-side thermal performance. A series of mathematical models were utilized in conjunction with operating data supplied by Ohio Edison and some baseline information taken at the plant to investigate:

- Furnace heat absorption profile
- Convection pass performance
- Boiler efficiency

- Boiler circulation; departure from nucleate boiling.

The following steps were taken to evaluate boiler thermal performance:

- Calculate or obtain physical data for the boiler components (e.g., heating surfaces, tube diameters, tube arrangement, tube material, free gas areas).
- Set up computer programs to calculate boiler efficiency, cyclone/furnace performance, convection pass performance, and air heater performance.
- Calibrate programs with baseline data. Determine required calibration factors to match baseline data.
- Calculate baseline boiler performance.
- Calculate boiler performance with reburn.
- Compare boiler performance with reburn to baseline performance.

Baseline Boiler Performance

In order to determine the impact of the reburn system on boiler performance it was first necessary to establish the current or baseline performance for reference purposes. The basis for making this calculation was operating data supplied by Ohio Edison together with some actual gas temperature data taken at the plant. The first step in calculating baseline performance was to establish boiler efficiency; this was done using the heat loss method. The calculated losses and resultant efficiency are shown in Table I. Knowing the boiler efficiency and the output of the unit allowed the coal input to be calculated. Based on the coal analysis shown in Table II, combustion calculations were performed to establish the gas and air weights. Sufficient information was now available from the above gas and air weights which, in conjunction with physical data taken from boiler drawings, allowed the convection pass program to be run. The convection pass program was run backwards to determine: (1) furnace exit gas temperature, (2) effective surfaces, and (3) intermediate steam and gas temperatures.

Furnace/cyclone performance calculations were performed next using C-E's lower furnace program. Program inputs were varied until certain conditions were met relative to a particular cyclone combustion efficiency, a particular gas temperature actually measured in the unit, and the furnace outlet temperature that was back-calculated by the convection pass program.

A heat absorption baseline profile was then generated using C-E's lower furnace program and is shown by the solid line in Figure 9; conditions for this calculation were 108 MW and 12% excess air. The heat absorption rates shown are perimeter average rates. Where heat transfer surfaces are more or less uniformly covered with refractory or ash deposits, the local rates should be reasonably close to the average rates. Where tube sections are not covered with refractory or ash deposits, local rates could be much higher than the average rates. The calculated average rate for the cyclone is approximately 83,000 Btu/hr-ft^2, and for the primary furnace and screen tubes the rates are approximately 54,000 and 44,000 Btu/hr-ft^2, respectively.

The total lower furnace heat absorption can be calculated by multiplying the heat absorption rates from the profile by the EPRS (Effective Projected Radiant Surface) and by correcting for casing heat loss. If the heat absorbed by the evaporative surface in the convection pass is added in, the sum should equal the heat absorbed by the fluid from the boiler inlet to the steam drum outlet; this was checked and was found to be in agreement within 2%.

Boiler Performance with Gas Reburn

Boiler performance with gas reburn was calculated in the normal forward design mode; i.e., the programs were run in the following order: (1) cyclone/lower furnace, (2) convection pass, (3) air heater, and (4) boiler efficiency. Process flow quantities were determined from assumptions regarding reburn natural gas flow rates, recirculated flue gas flow rates, additional air flow rates, and the exact locations of the above injectors.

For predicting performance with reburn, the lower furnace program was run with the firing rate in the cyclones reduced by 20%. Excess air was maintained at the same level as that of the base case, 12%. Boundary surface conditions (waterwall deposits) were varied in the secondary furnace: (1) in one case they were kept at the same condition as the back-calculated value for the base case, and (2) in the other case it was assumed that there would be about 30% less thermal resistance because of the decreased amount of coal being fired and the expected lower gas temperatures and changes in ash deposit characteristics.

The calculated heat absorption profile for the reburn case is shown with a dotted line in Figure 9. The profile indicates a 10% reduction in overall waterwall heat absorption with reburn where it is assumed that the thermal resistance of ash deposits will remain the same as for the base case. If it is assumed that the thermal resistance drops by about 30% in the secondary furnace, then the overall waterwall heat absorption would be about 5% less with reburn than for the base case.

Utilizing the output from the lower furnace program the convection pass program was then run to show superheater and reheater performance. The effective heating surfaces calculated from the base line data were input into the program. A weighted fuel analysis (80% coal + 20% natural gas) was used to calculate changes in gas properties. Primarily because of higher gas mass flows, due to the recirculated flue gas, more heat is picked up in the convection pass with reburn than for the base case. Slightly more heat is also picked up by the air heater with reburn.

One consequence of picking up more heat in the convection pass is that superheater spray water increases. However, the calculated increase in superheat spray is within the capability of the unit even under a worst case scenario. Parametric testing might well show that the maximum amount of recirculated flue gas, for example, is not needed to achieve effective mixing; decreases in recirculated flue gas flow rate will have a direct effect on heat transfer in the lower furnace and convection pass, specifically more heat would then be picked up in the furnace and less in the convection pass.

As shown earlier in Table I the boiler efficiency with natural gas reburn will be about 0.5% less than the base case primarily due to greater moisture from fuel losses; i.e., the higher hydrogen content of the natural gas results in more water vapor being formed than when firing coal.

Two other boiler thermal performance related questions were addressed, namely the effect of reburn on boiler circulation and the effect of reburn on departure from nucleate boiling (DNB). DNB is defined as the occurrence of film boiling under which the tube inside (water side) heat transfer coefficient drastically deteriorates and tube overheating/failure usually results.

A computer program was used to perform boiler circulation calculations. In general the program balances the pressure drops of the multiple parallel circuits based on available thermal heads between the downcomers and risers. Both baseline and reburn cases were investigated. The results of this study have shown that tube offsetting, for purposes of making openings for fuel and air injectors, would have an insignificant effect on circuit flow and exit circulation ratio.

Relative to the question of DNB, evaluation of the division wall between the primary and secondary furnaces was addressed since it sees the heaviest duty. The criterion for evaluation of DNB is specification of the maximum allowable steam quality which depends on pressure, heat flux, and mass flow of water/steam. To avoid DNB the actual circuit steam quality must be kept less than the maximum allowable steam quality and with adequate safety margin. Based on calculations it has been determined that 56% steam quality (or less) ensures a DNB free condition. The actual steam quality in the highest duty location, the division wall, is calculated to be well under 10% with reburn. The occurrence of DNB is not seen as a problem.

Impacts of Reburn on Boiler Tube Life

The presence of a slightly reducing condition in the reburn zone has raised questions about the potential for tube corrosion when operating a boiler with a reburn system. In response to this concern two things have been/will be done: (1) previous relevant experience has been examined, and (2) precautionary measures will be taken during all field testing to monitor tube wastage.

Mitsubishi Heavy Industries (MHI) has operated units in Japan which have their version of reburn systems (MACT) installed on them (8). Experience gained from these tangentially fired MACT-equipped units (all of which employ oil as the reburn fuel) has shown no more wastage than normally expected after as many as 3 years of operation (Table III). One of the units co-fired oil and coal, another fired oil and gas, and the third fired LNG as the main fuel. Though none of the units was a cyclone fired boiler it seems reasonable to believe that the chemical conditions in the reburn zone should be quite similar regardless of boiler type if held to the same air/fuel stoichiometries of 0.90 - 0.95. Additionally it seems reasonable to assume that the use of natural gas as a reburn fuel rather than sulfur-containing oil should produce results which are equal to (in the worst case) or better than those achieved with oil.

Table IV shows data collected from long term corrosion testing on three coal fired boilers where staged air, low NO_x systems have been in operation for about 2 years (10). A combination of integral test panels and corrosion probes have produced data which show wastage rates averaging between 1.5 and 3.9 mils (38 and 99 μm) per year. These data indicate, as do those from MHI, that wastage rates produced from low stoichiometric firing/reburn zones are not significantly different from those typical of conventionally operated units.

A combination of corrosion probes and ultrasonic testing (U.T.) will be used during testing of Ohio Edison's Niles Unit 1 boiler. Corrosion probes have the advantage of being removable at any time without shutting down the boiler. Ultrasonic testing has the advantage of being able to monitor a large number of tubes without the need for penetrations in the boiler. C-E has extensive experience with the use of corrosion probes and U.T. measurements as reliable means for monitoring tube wastage (11, 12).

SUMMARY

Reburning is an in-furnace NO_x reduction technology that is uniquely well suited for cyclone fired boilers. A reburn system has been designed for Ohio Edison's Niles Unit 1 which meets the theoretical criteria for effective NO_x reduction.

The number and location of reburn fuel and additional air injectors to achieve effective mixing have been determined from extensive cold-flow modeling tests and a further consideration to minimize the impact on boiler/plant modifications. Mathematical modeling has determined that there will be a slight shift in heat absorption patterns in the boiler when the reburn system is operated but that the changes are well within the framework of boiler operational tolerances for satisfactory and reliable boiler performance. Based on relevant experience it has been determined that boiler tube life was not significantly changed by operating either with reburn systems employing oil as the reburn fuel or with staged-air low NO_x systems. A combination of corrosion probes and U.T. measurements will be employed to carefully monitor tube wastage. Progress to date continues to indicate that reburning should be a commercially viable in-furnace NO_x reduction technology for cyclone fired boilers.

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The authors gratefully acknowledge the contributions of each of these people.

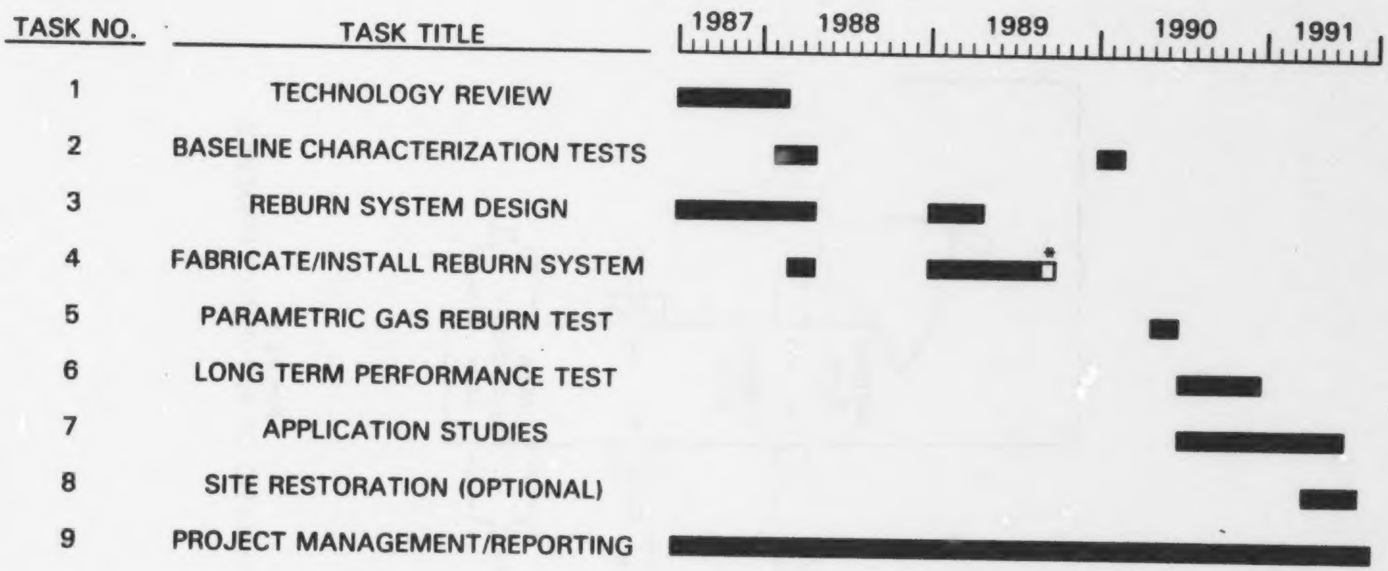


Figure 1
PRELIMINARY OVERALL PROJECT SCOPE AND SCHEDULE

* THE OPEN AREA IN THE BAR REPRESENTS THE ACTUAL 30 DAY OUTAGE WHEN THE UNIT IS OFF LINE

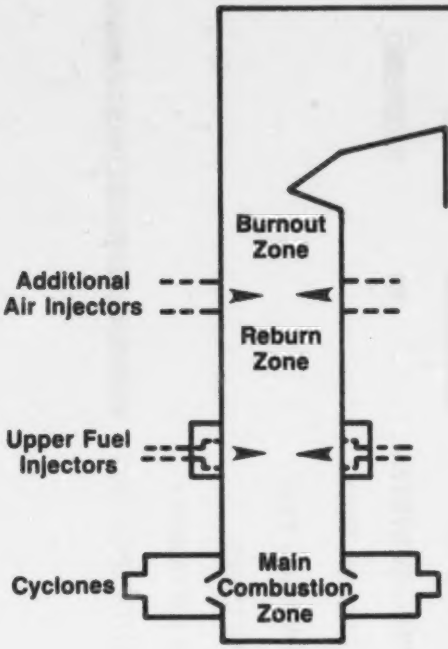

Burnout Zone
Additional Air Injectors
Reburn Zone
Upper Fuel Injectors
Cyclones
Main Combustion Zone

Figure 2
SCHEMATIC OF REBURNING PROCESS

Reproduced from
best available copy.

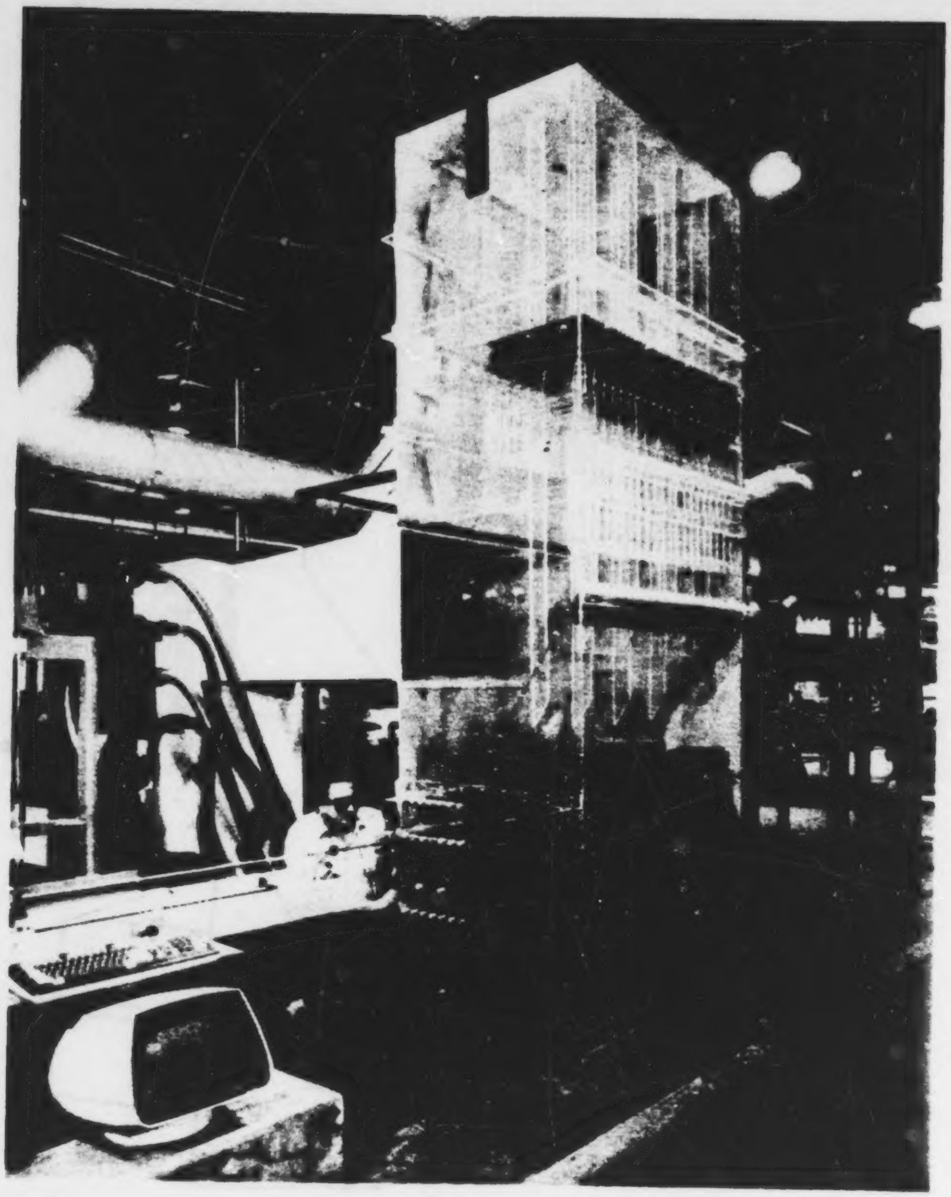


Figure 3
PHOTOGRAPH OF ONE-NINTH SCALE FLOW MODEL

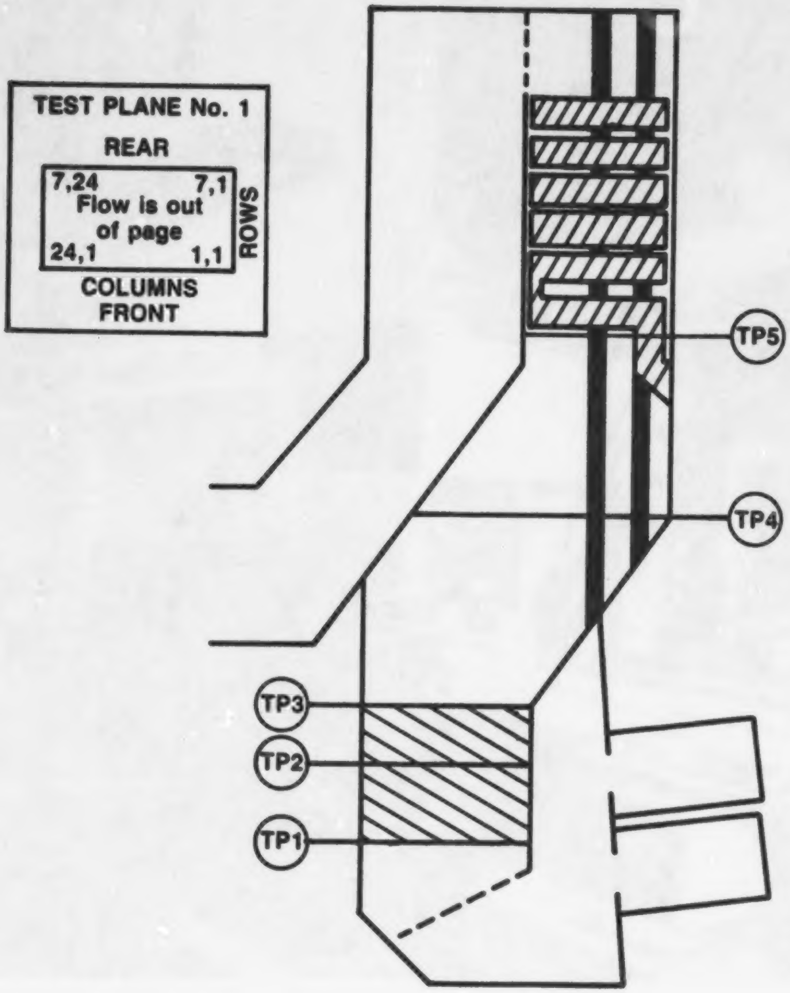

TEST PLANE No. 1
REAR
7,24
7,1
Flow is out of page
24,1
1,1
ROWS
COLUMNS
FRONT
TP5
TP4
TP3
TP2
TP1

Figure 4
TEST PLANE LOCATIONS

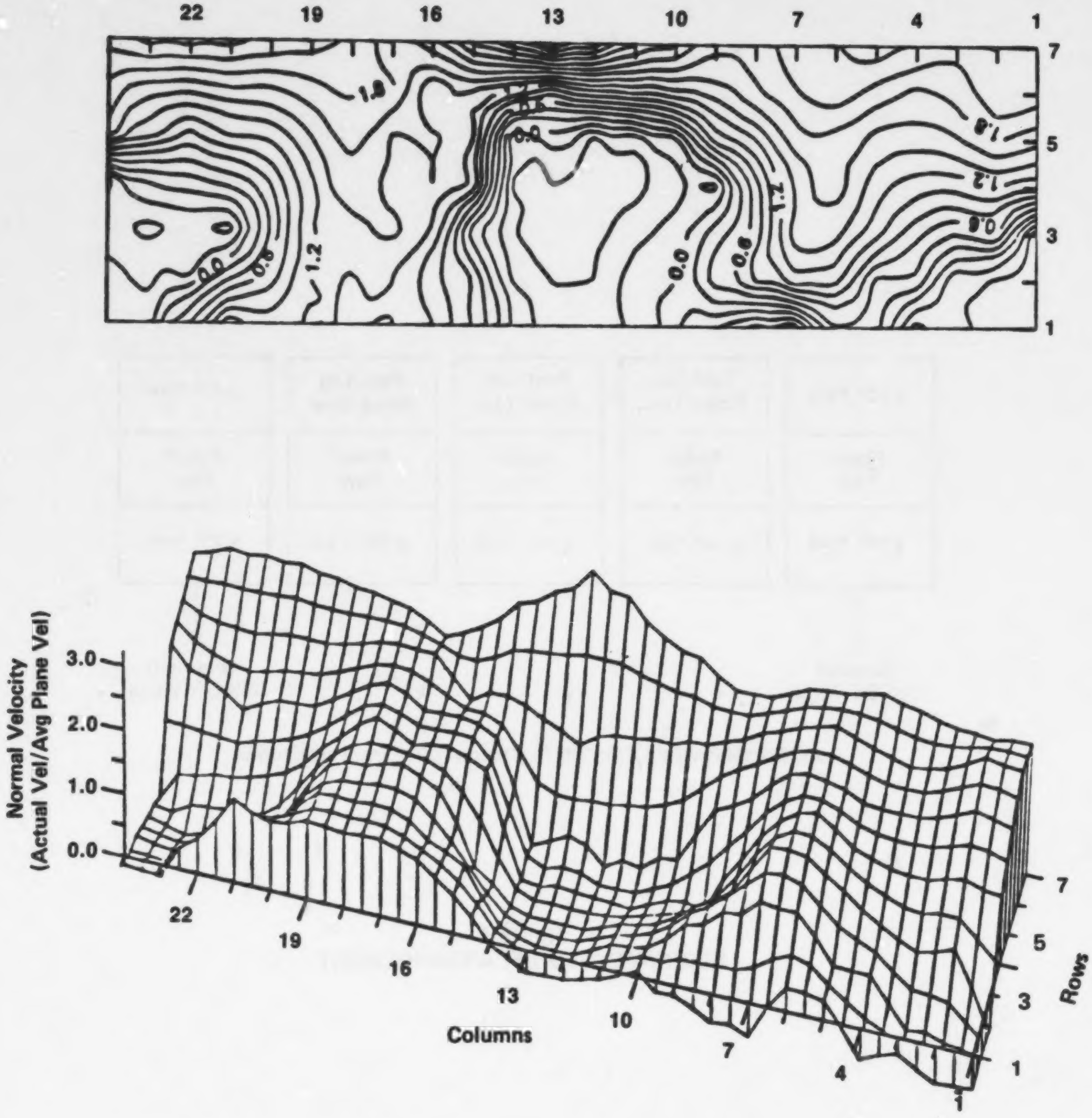
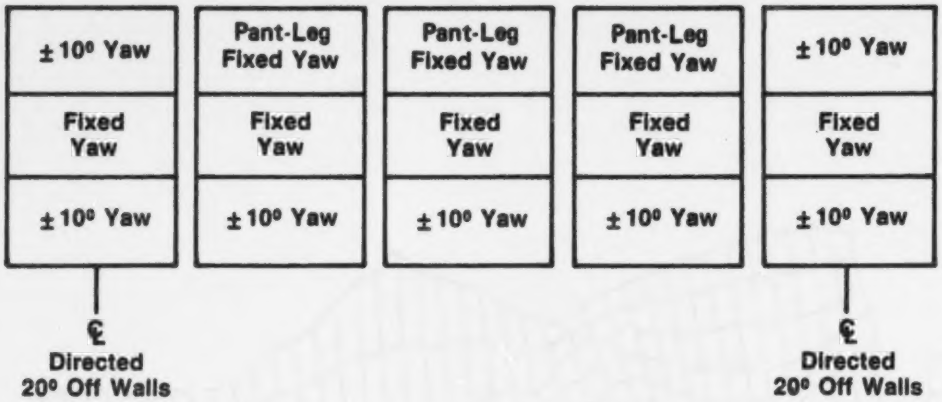


Figure 5
NORMALIZED VELOCITY PROFILE AT ENTRANCE
TO THE REBURN ZONE


±10° Yaw
Pant-Leg Fixed Yaw
Pant-Leg Fixed Yaw
Pant-Leg Fixed Yaw
±10° Yaw
Fixed Yaw
Fixed Yaw
Fixed Yaw
Fixed Yaw
Fixed Yaw
±10° Yaw
±10° Yaw
±10° Yaw
±10° Yaw
±10° Yaw
℄ Directed 20° Off Walls
℄ Directed 20° Off Walls

All Compartments Can Tilt In Unison ±25° from Horizontal

Figure 6
RECOMMENDED UFI ARRANGEMENT

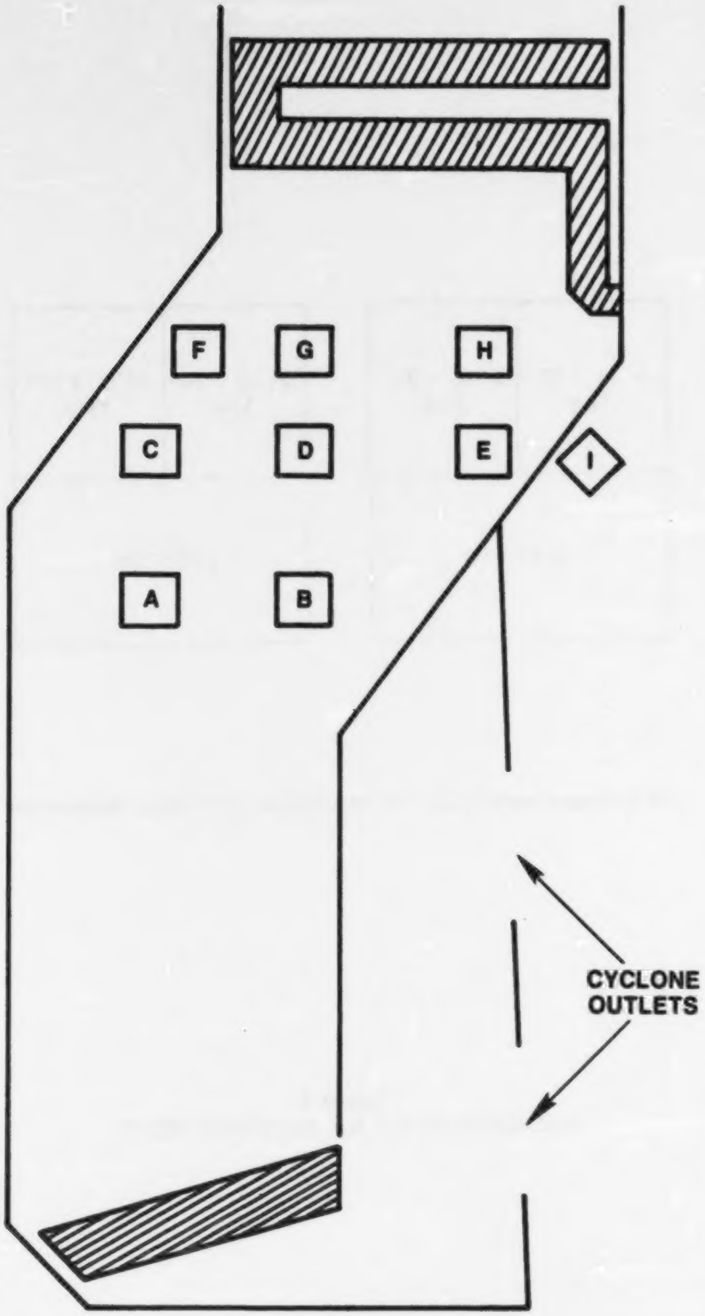
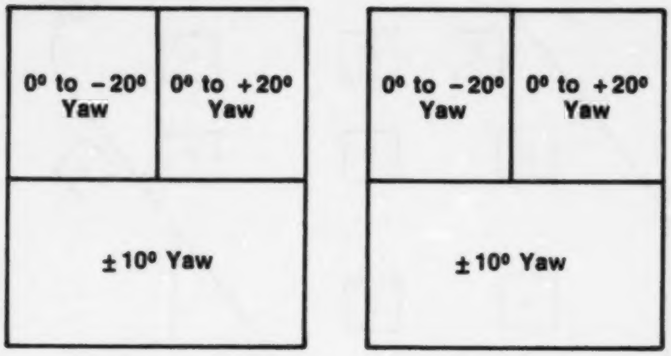

F
G
H
C
D
E
I
A
B
CYCLONE OUTLETS

Figure 7
AA INJECTOR LOCATIONS EVALUATED


0° to −20° Yaw
0° to +20° Yaw
± 10° Yaw
0° to −20° Yaw
0° to +20° Yaw
± 10° Yaw

All Compartments Can Tilt In Unison ±25° from Horizontal

Figure 8
RECOMMENDED AA ARRANGEMENT

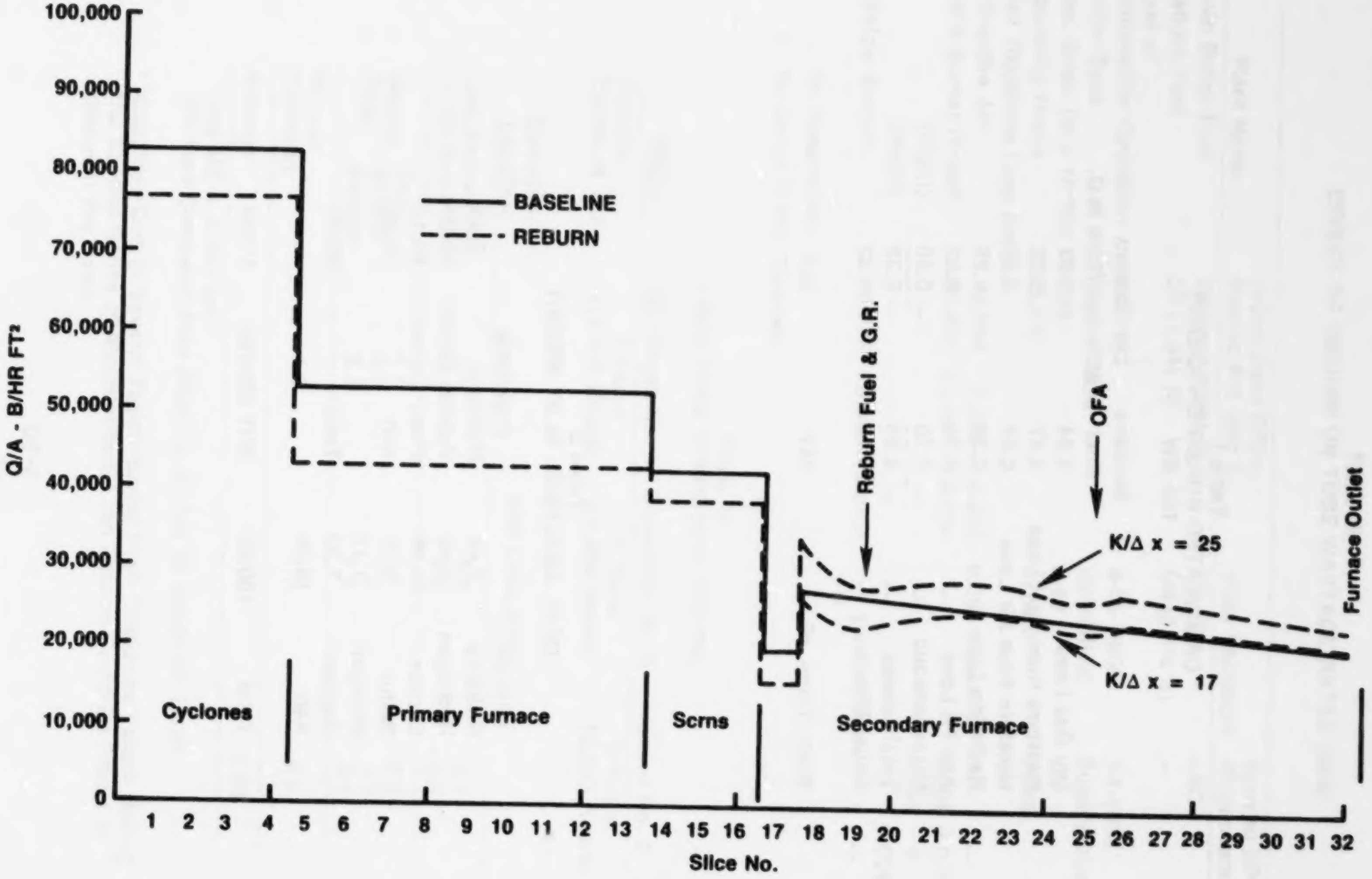


Figure 9
FURNACE HEAT ABSORPTION RATE
OHIO EDISON - 108 MW
(12% XA)
STRIP AVERAGE

Table I
CALCULATED BOILER EFFICIENCY
108 MW

	Baseline Coal	Reburn 80% Coal/20% N.G.
Dry Gas Loss	2.84	2.63
Moisture from Fuel Loss	4.47	5.32
Moisture from Air Loss	0.07	0.06
Radiation Loss	0.24	0.25
Ash Pit Loss	0.74	0.62
Miscellaneous	0.50	0.50
Total Losses	8.86	9.38
Boiler Efficiency	91.14	90.62
Stack Temp. °F	267	269

Table II
COAL ANALYSIS - % BY WEIGHT

Ultimate		Proximate	
Moisture	7.45	Moisture	7.45
Hydrogen	4.48	Volatile Matter	35.05
Carbon	63.00	Fixed Carbon	44.14
Sulfur	3.26	Ash	13.36
Nitrogen	1.12		
Oxygen	7.33	Total	100.00
Ash	13.36		
Total	100.00	HHV (Btu/lb)	11559

Table III
EFFECT OF REBURN ON TUBE WASTAGE RATES (MHI)

Plant Name	Joban Joint EPCo. Nakosa P/S Unit 8			Yuka Yokkaichi			Kyushu EPCo. Shinkokara P/S Unit 5		
Main Boiler Fuel	Oil/Coal (0.3% S)			Oil, Gas			LNG		
Reburn Fuel	Oil (1.8% S)			Oil (2.6% S)			—		
Date of Commercial Operation	9-9-1983			6-25-1982			7-1-1983		
Boiler Type	Supercritical			Subcritical			Supercritical		
Max. Evap. (lb x 10^{-6}hr)	4.29			0.62			4.3		
Operating Hours	25,912			27,320			7,389		
Wall Thickness Loss (in)									
Overfire Air	0.004	0.003	+0.003	0.005	0.004	0	—	—	—
Mid Burner (Front)	<0.001	+0.001	+0.004	—	—	—	0.008	0.008	0
(Right)	—	—	—	—	—	—	0.008	0	+0.004
(Right)	—	—	—	—	—	—	0	0.004	0
Below Burner	+0.016	+0.008	0.001	—	—	—	—	—	—

— No Measurement

0 No Change in Wall Thickness

Table IV
LONG TERM CORROSION TESTING

Boiler	Mill Creek No. 3	Conesville No. 5	Hunter No. 2
On-Line Exposure Time	2 Years (15,000 Hours)	2 Years (12,000 Hours)	2 Years (~18,000 Hours)
Elevation/ Location	Wall Loss, mils*		
Just Below Nose	4.0	0.8	3.1
~ 15ft Below Nose	3.4	2.0	−0.5**
Burner Zone Top	4.4	2.1	2.5
Burner Zone Middle	3.7	1.8	1.7
Burner Zone Bottom	3.5	2.9	2.1
Hopper Elevation	4.8	1.5	0.8
Average	3.9	1.9	1.53

*One Mil = 0.001 Inch
(To Find Corrosion Rate (Mils/Yr), Divide by Exposure Time).

**Gain Was Due to Several Tubes Having High Thickness Values During the Second Series of Measurements (No Reason Could Be Found to Discount the Data).

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DESIGN METHODS FOR LOW-NOx RETROFITS
OF
PULVERIZED COAL FIRED UTILITY BOILERS

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ABSTRACT

Babcock-Hitachi K.K. has partially reconstructed an existing pulverized coal fired 350 MWe boiler by changing conventional low-NOx Dual Reyister type burners with Hitachi-NOx Reduction (HT-NR) type burners. The HT-NR burner was developed, as presented in the 1985 EPRI/EPA Joint Symposium on Stationary Combustion NOx Control, to meet the concept of promoting "In-Flame" NOx Reduction. And two 200 MWe retrofitted boilers have been changed from conventional low-NOx Dual Register burners to HT-NR burners, as presented in the 1987 EPRI/EPA Joint Symposium on Stationary combustion NOx Control, which have achieved further NOx reduction without increased carbon in fly ash and also without an increase of excess furnace air. This 350 MWe retrofit has marked the second trial whereby a HT-NR technique has been carried out for a retrofit on a full-scale utility coal-fired boiler, and a reasonable NOx figure was confirmed. This paper introduces the design concept for several kinds of low-NOx retrofits with our recent 90 x 10^6 Btu/h pilot test results and the above field experiences.

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INTRODUCTION

At present the low-NOx combustion method employing fuel-rich reactions, such as air-staging low-NOx burners or Two Stage Combustion (TSC), is the most practical method in reducing fuel NOx from pulverized coal fired utility boilers. The following items will be discussed to evaluate the NOx, combustion efficiency, excess air and boiler performance etc.

Furnace effect ----- with or without Two Stage Combustion
Burner effect ----- promoting In-Flame NOx Reduction
Fuel property ----- Volatile hydrocarbon effect to decompose Nitrogen Oxides

DESIGN CONCEPT

NOx Performance

Figure 1 shows the behavior of NOx (mainly NO) formation in the boiler furnace.

Burner Zone NOx Formation. Primary NOx formation NOx,o may be described by the equation 1.

$$\mathrm{NOx,o} = \begin{cases} k_1 \cdot \exp\left[(\mathrm{BHR})\left(\frac{\mathrm{SR}}{\mathrm{SR_o}}\right)^{\alpha_1}\right] \text{ ----- } \mathrm{SR} > \mathrm{SRo} \\ k_1 \cdot \exp\left[(\mathrm{BHR})\left(\frac{\mathrm{SR}}{\mathrm{SR_o}}\right)^{\alpha_2}\right] \text{ ----- } \mathrm{SR} < \mathrm{SRo} \end{cases} \text{ --------- } (1)$$

$$(\alpha_1 > \alpha_2 > 1,\ \mathrm{SRo} = 1.0 \sim 1.2)$$

The Burner Zone Heat Release Rate (BHR), has direct effect on the average flame temperature. Thermal NOx formation, by Zeldovich's mechanism, strongly depends on the oxidizing flame temperature shown in Figure 2. Therefore, in general, the burners should be optimally arranged to decrease BHR if the furnace does not have Two Stage Combustion equipment. (SR ..... Burners zone Stoichiometric Ratio) In the equation 1, factor k_1 depends on the content of fuel nitrogen in coal (N_{daf}), and depends on the reduction efficiency of the total fixed nitrogens (= $NO + NH_3 + HCN$) in the burner flame. That is,

$$k_1 = \xi_1 (N_{daf})^{\beta_1} \cdot [1 - \eta_N] \text{ ------------------------------------- } (2)$$

$$(0 < \eta_N < 1), (\text{"daf" ----- dry, ash free basis})$$

It should be strongly remarked that the reduction efficiency of the total fixed nitrogens (η_N) is promoted by the hydrocarbon intermediates evaporated from coal particles, and accelerated by increasing the temperature of the fuel-rich flames. Rapid ignition near the burner throat and finer coal particle distribution can promote an increase in the temperature at the initial stages of combustion under enhanced fuel-rich conditions.

$$\eta_N = R \exp\left(-\gamma_1 \frac{FR}{FR_0} - \gamma_2 \frac{DP}{DP_0} + \gamma_3\right) \text{ --------------------------- (3)}$$

$(R, \gamma_1, \gamma_2, \gamma_3 > 0)$, (R --- Burner Performance Factor)

As described in equation 3, FR (= [Fixed Carbon]/[Volatile Matter]) and D_P (average coal particle diameter) are the important fuel factors for low-NOx retrofits. Finer pulverizing, however, would require larger pulverizers or an increase in their power consumption.

The HT-NR burner, shown in Figure 3, is one of the modern low-NOx burners proven in field operation to maximize η_N, keeping total combustion efficiency. A valuable feature of the HT-NR burner is its ability to produce rapid ignition and consequently high temperature reducing flames with Flame Stabilizing Ceramic Rings fitted to the edge of the fuel nozzles, as a result of which reducing agents are generated effectively. And the External Air Guide Sleeve is fitted with a collar which contributes to maintaining the external (outer) air apart from the reducing combustion zone.

NOx Decay in the Post Flame Zone. NOx can be reduced in the space between the burner zone and after-air (overfire air) injection ports, if the furnace is adopted with a Two Stage Combustion. This post-flame NOx decay phenomena will be promoted by enough residence time of combustion gas from the burner zone to after-air (overfire air) injection ports.

In the Figure 1, therefore, NOx behavior may be described by the equation 4.

$$NOx^* = NOx,o[1 - \eta_1] \text{ --- (4)}$$

η_1 depends on the Combustion Gas Residence Time, RT_1, from burner zone to after-air (overfire air) injection ports. Therefore,

$$\eta_1 = 1 - \exp\left(-\alpha_3 \frac{RT_1}{RT_0}\right) \text{ ------------------------------------ (5)}$$

$(\alpha_3 > 0)$

Modern low-NOx furnaces can have enough RT_1. But on many existing old style low-NOx furnaces, proper attention to RT_1 was not paid during the design/construction stage.

NOx Reformation by After-Air (Overfire Air) Injection. If oxidizable nitrogen compounds such as NH_3 or HCN remain before after-air (overfire air) injection, a great deal of these species may be converted to NOx, and a part of nitrogen in chars (Char-N) will also be converted to NOx during heterogeneous combustion of the residual coal chars by after-air (overfire air) injection.

Nitrogen in raw coals was effectively evaporated to gaseous substances by rapid ignition and increasing the temperature of the fuel-rich flame separated from oxidizing flame. Consequently, the total fixed nitrogen (= NO + NH_3 + HCN) was minimized before after-air (overfire air) injection.

Given this aspect, the final NOx emission (NOx, final) from the boiler furnace is described by the equation 6, 7 and 8.

$$\mathrm{NOx,final} = \mathrm{NOx}^* + \mathrm{Reformation} \quad \text{------------------------------} \quad (6)$$

$$\mathrm{Reformation} = k_2 \exp \left[- \left(\frac{SR}{SR_o} \right)^{\alpha 4} \cdot \left(\frac{RT}{RT_o} \right)^{\alpha 5} \right] \quad \text{----------------} \quad (7)$$

$$k_2 = \xi_2 \, (\mathrm{Ndaf})^{\beta_2} \, [1 - \eta_N] \quad \text{-----------------------------------} \quad (8)$$

$$(\alpha_4, \alpha_5 > 0)$$

So, k_i (i = 1,2) is an important fuel factor in the Fuel NOx reduction efficiency for low-NOx techniques using fuel-rich reactions, regardless of whether the boiler furnace has Two Stage Combustion equipment or not.

Combustion Efficiency

Delayed mixing of air-coals could decrease the combustion efficiency in many cases. Figure 4 shows the multi-stage model of coal combustion in the furnace for two cases. Curve A and B are calculated for single stage combustion (without after-air ports) and curve A' and B' are calculated for Two Stage Combustion (burner zone stoichiometric ratio = 0.9 ~ 1.0). Coal A has a higher Volatile Matter and coal B has a lower Volatile Matter. Higher volatile coal (generally FR < 1.2) has a relatively large combustion rate constant of the heterogeneous char burning in the complete combustion zone (from after-air injection ports to furnace exit). Therefore Two Stage Combustion retrofitted boilers (from Single Stage Combustion to Two Stage Combustion) can make less effect on combustion efficiency, if higher volatile coals are fired. On the other hand, the Two Stage Combustion retrofitted boilers fired lower volatile coal (generally FR > 1.5, especially FR > 2.2) will make a more or lesser decrease of combustion efficiency.

Also conventional delayed air-fuel mixing type low-NOx burners could affect the unburned carbon loss. Therefore the "trade-off" relationship of NOx and unburned carbon loss could be unavoidable for lower volatile coal firing without finer coal particle modification and/or without increased excess air. Only increasing the temperature of fuel-rich flames, separated from the oxidizing zone in the burner flame, may cast off the skin of the "trade-off" defect.

CASE STUDIES FOR LOW-NOx RETROFITS

Figure 5 shows several cases of modern low-NOx retrofits of the existing low-NOx furnace.

- Case I (A + B) : only replace of conventional low-NOx burners with modern low-NOx burners (HT-NRs)
- Case II (A + C) : only addition of after-air (overfire air) ports
- CaseIII (B + D) : B + after-air ports
- Case IV (C + D) : C + replace of conventional low-NOx burnrers with modern low-NOx burners (HT-NRs)
- Case V (A + D) : A + replacement of conventional low-NOx burners and addition of after-air ports

Figure 7 shows the pilot evaluation of the above retrofit cases, all data was obtained by Babcock-Hitachi K.K.'s new 90 x 10^6 Btu/h test facility (see Figure 6). Three kinds of coals were tested in each case. The following results were obtained as shown in Figure 7.

- Not only Two Stage Combustion but also burner replacing achieved remarkable NOx reduction.
- The HT-NR effect on NOx reduction, depending on volatile content of coal, causes no harmful effects on combustion efficiency under the same burner stoichiometric ratio, excess air and pulverized coal fineness.

Therefore net NOx reduction efficiency may be described in Table 1.

FIELD EXPERIENCES

Background

As previously reported in the 1987 Symposium in New Orleans, two identical 200 MWe P.C. fired boilers have been retrofitted by replacing conventional Dual Register type burners with HT-NR type burners. This retrofitting corresponds to the above-mentioned case IV (C + D), and 35 ~ 45 % of NOx reduction efficiency by the retrofitting was confirmed for coals which had 31 ~ 52 % Volatile Matter (dry, ash free basis) under the same condition of the burner zone stoichiometric ratio, furnace excess O_2 and pulverized coal fineness before and after retrofitting. And noteworthy the carbon in fly ash was reduced slightly after this HT-NRs retrofitting. Minimum NOx emissions,70 ~ 75 ppm (corrected to 6 % O_2) leaving economizer, were confirmed when firing a higher volatile coal (Volatile Matter (d.a.f.) = 52 %) under very low carbon in fly ash (< 3 %).

The second trial of the retrofitting case IV (C + D) was executed at the 350 MWe P.C. fired boiler in mid 1987. This boiler furnace has a stricter physical volumetric space both of RT_1 and combustion completion space from the after-air injection ports to the furnace exit. Because the original design was centeralized around the conventional Two Stage Combustion only for a Japanese domestic coal and it had only been operated for higher volatile (Volatile Matter (d.a.f.) = 50 %) Japanese coals. For recent economical reasons, however, coal must be blended with imported coals (Volatile Matter (d.a.f.) = 30 ~ 40 %), and NOx emission from the boiler furnace has to be less than 180 ppm (corrected to 6 % O_2) in commercial operation required under the conditions of the same excess air (or excess O_2) and allowable unburned carbon loasses.

Specification and Retrofit Items

Figure 8 shows the boiler furnace configuration.

The entire furnace enclosure is formed with membrane walls and these are 3 horizontal rows of 6 burners in the front wall and 2 horizontal rows of 6 burners in the rear wall, total 30 burners. The burners, before-retrofit, were conventional low-NOx Dual Register type, then partially reconstructed to Hitachi-NR (HT-NR) type. The burner throat size was enlarged to meet the change of coal properties during this retrofit. Details of this retrofit are shown in Figure 9 and Table 2.

About 2 months outage was allowed for the retrofit.

Operating Results

The project of retrofitting was conducted in three stages : before-retrofit combustion testing, replacing, after-retrofit combustion testing using the same coal property as before-retofit's.

Table 3 shows the coal specifications during the combustion tests.

After the combustion test, this unit was put into service with the same low-NOx performance as the after-retrofit combustion testing.

Combustion Performance. Figure 10 shows NOx emissions and carbon in ash from the 350 MWe unit before and after retrofitting. The coal property (a blend of Japanese coal and Canadian coal) is the same as before and after retrofit. Average value of FR (= [Fixed carbon]/[Volatile Matter]) was 1.3. Some Mill Balls were maintained at this retrofit. So the pulverized coal fineness, by percentage of weight through a 200 mesh sieve, was 70 % before retrofit and changed to 65 ~ 70 % after retrofit in this combustion test.

About 30 % of NOx reduction efficiency (η_{NOx}) was confirmed under the condition of the same carbon in fly ash before and after retrofit. And there was no need to increase excess air to maintain the same carbon in fly ash as before the retrofit.

Figure 11 shows the NOx reduction efficiency (ηNOx) in this retrofit as compared with the 200 MWe retrofit. A reasonable NOx reduction efficiency rate was confirmed as shown here.

Figure 12 shows tuned NOx emission performance levels at each boiler load (turbine output, MWe). The HT-NR burner promoted the flame stabilization and made a more visible "clear-cut" flame than that of before retrofit. This confirmed complete flame stability on the Flame Stabilizing Ceramic Rings at 79 MWe (22.5 % of boiler load) - 350 MWe (100 % of boiler load) without oil supporting. Output voltage of flame signal by flame detectors (Hitachi Dual-Signal type) at each burner was compared before retrofit with after retrofit, as shown Figure 13.

Boiler Performance. Figure 14 shows the results of the steam temperatures before and after retrofit. There was no significant difference before retrofit and after retrofit. And this HT-NR retrofit produced no undersirable effects on the boiler performance concerning the steam generation.

Slagging and Sootblowing. The sootblowing patterns and operating intervals were not changed, but the ash deposition around the burner throat was remarkably reduced by this HT-NR retrofit. This result might be of great use in measures against fire-side wall corrosion of furnace, that have been through long term inspection stages since the HT-NR retrofit.

CONCLUSION

The partial reconstruction of conventional low-NOx burners by using the Hitachi-NR burner's design concept has been focused upon throughout this paper by presenting the 350 MWe retrofitted boiler in a series of 200 MWe retrofitted boiler. As a result, the low-NOx capability of the HT-NR burner was brought to light. Babcock-Hitachi K.K. confirms that these retrofitted applications of HT-NR burners will be greatly adaptable to many existing P.C. fired boilers with or without Two Stage Combustion and, will certainly be of greater use and more beneficial to modern low-NOx boilers.

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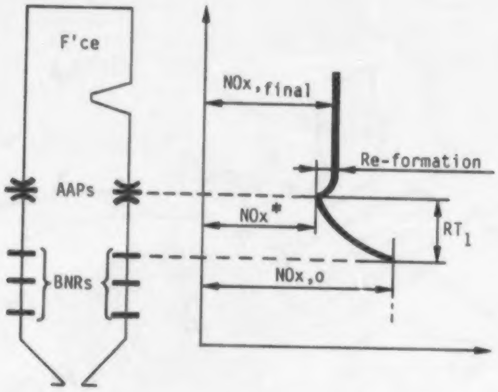

F'ce
NOx,final
Re-formation
AAPs
NOx*
RT1
BNRs
NOx,o

Fig. 1 Behavior of NOx formation in furnace

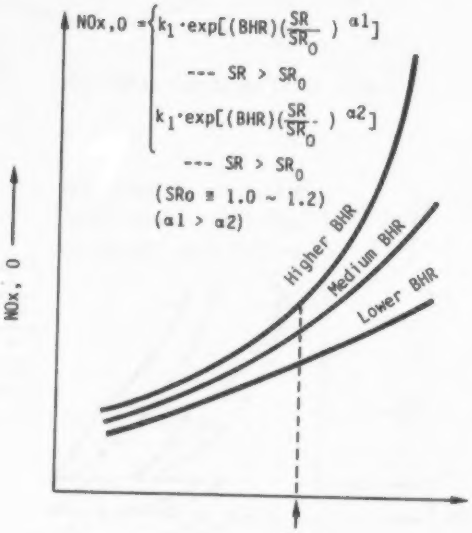


Fig. 2 BHR effect on NOx,0

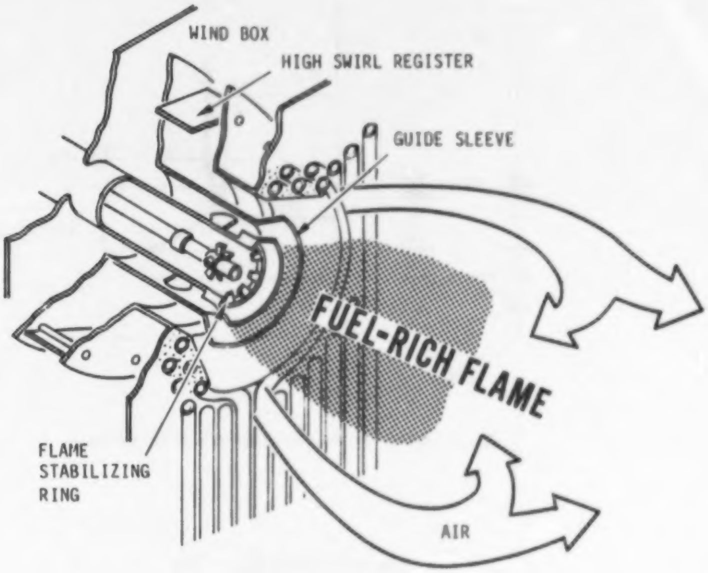
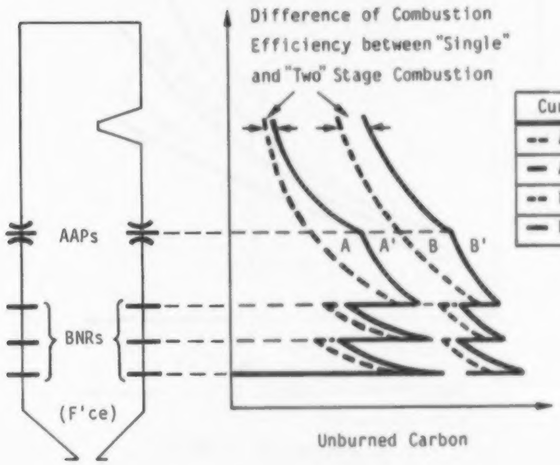
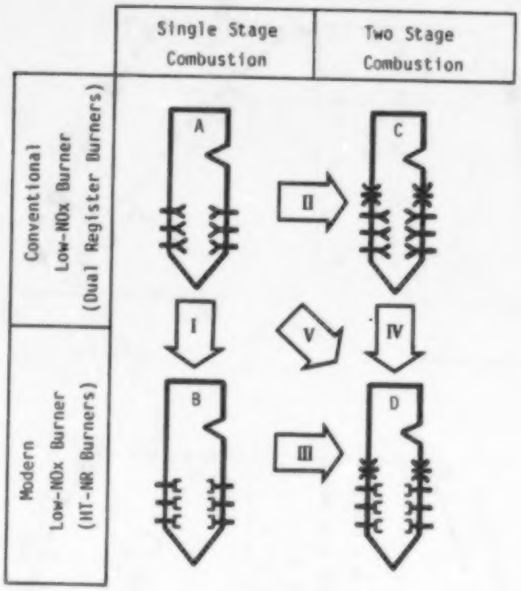

WIND BOX
HIGH SWIRL REGISTER
GUIDE SLEEVE
FUEL-RICH FLAME
FLAME STABILIZING RING
AIR

Fig. 3 HT-NR Burner Structure



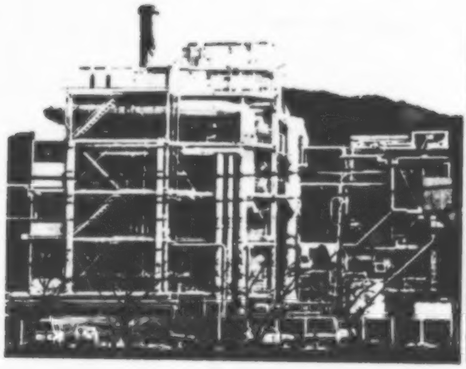
Curve	Coal	TSC
-- A --	FR = 1	Without
— A' —		With
-- B --	FR = 2	Without
— B' —		With

Fig. 4 Behavior of Unburned Carbon


Single Stage Combustion
Two Stage Combustion
Conventional Low-NOx Burner (Dual Register Burners)
Modern Low-NOx Burner (HT-NR Burners)
A
C
II
I
V
IV
B
D
III

(Furnace has the same volume as each case.)

Fig. 5 Cases of Low-NOx Retrofit



Furnace Type	Water Jacket, Vertical
Heat Input	90 x 10^6 Btu/h
F'ce Dimension	Width : 4.5 m Depth : 3.3 m Height : 20 m
Burner Arrangement	2 Burners x 3 Rows, Opposed Total 12 Burners
AAP Arrangement	2 Ports x 3 Rows, Opposed Total 12 Ports
Pulverizer	MPS Roller type Mill x 1 Tube Mill x 1

Fig. 6 Test Facility

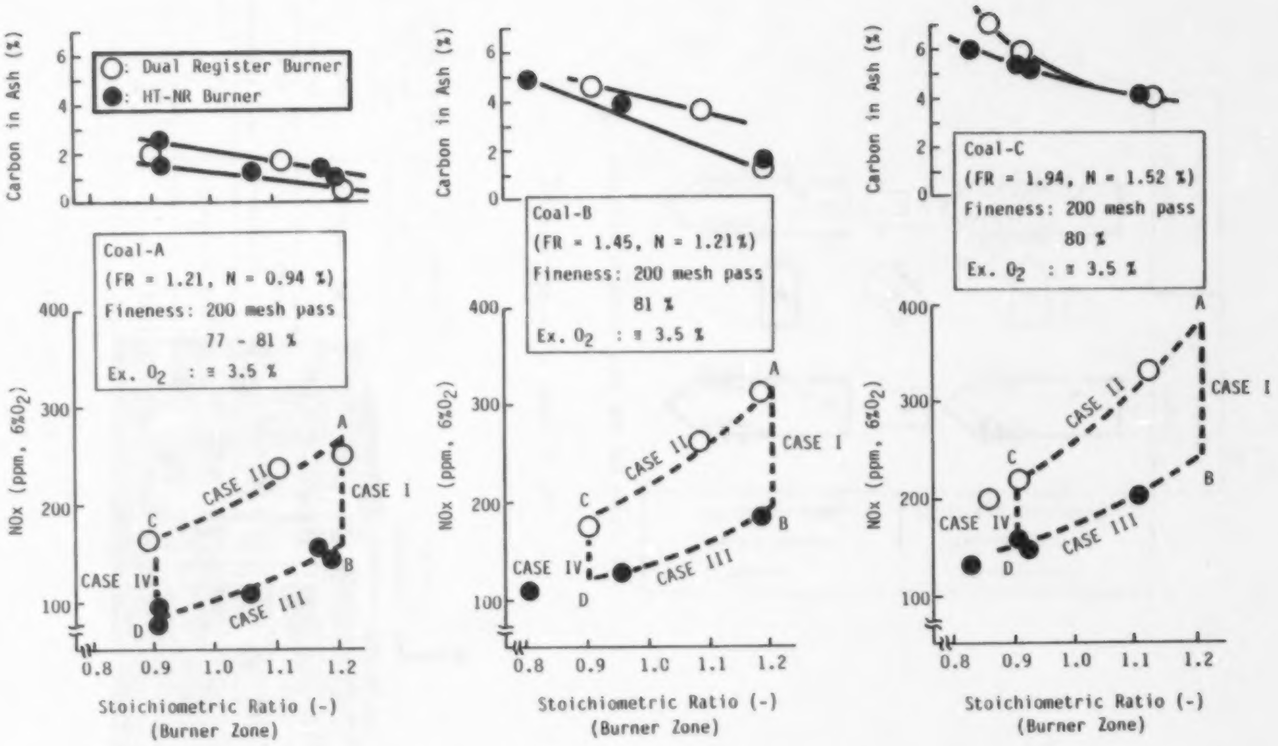
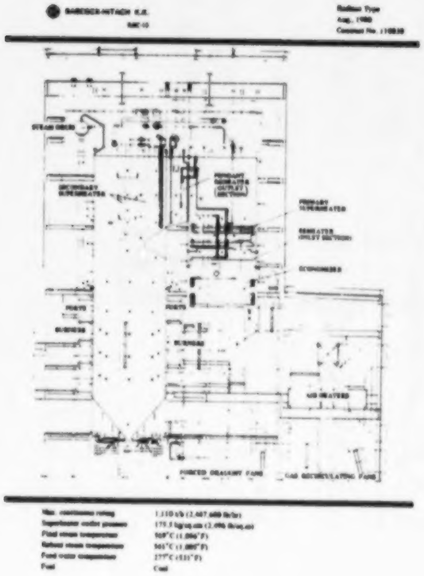


Fig. 7 Pilot evaluation for low-NOx retrofit


BABCOCK-HITACHI K.K.
STEAM DRUM
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
REHEATER (INLET SECTION)
ECONOMIZER
PORTS
BURNERS
AIR HEATERS
FORCED DRAUGHT FANS
GAS RECIRCULATING FANS

Boiler Type	BHK Natural Circulation
Max. continuous rating	1,110 t/h
Superheater outlet press.	175.5 kg/sq·cm
Final Steam Temp.	569 °C
Reheat Steam Temp.	541 °C
Feed Water Temp.	277 °C
Draft Type	Balanced Draft
Burner Arrangement	Front: 6 Bnrs x 3 Rows Rear : 6 Bnrs x 2 Rows (Total 30 Bnrs)
Mill Type	BHK E type Mill Total 5 Mills No Standby
Remark	Furnace was designed for Hight-Volatile Domestic coal fired.

Fig. 8 350 MWe Boiler Unit

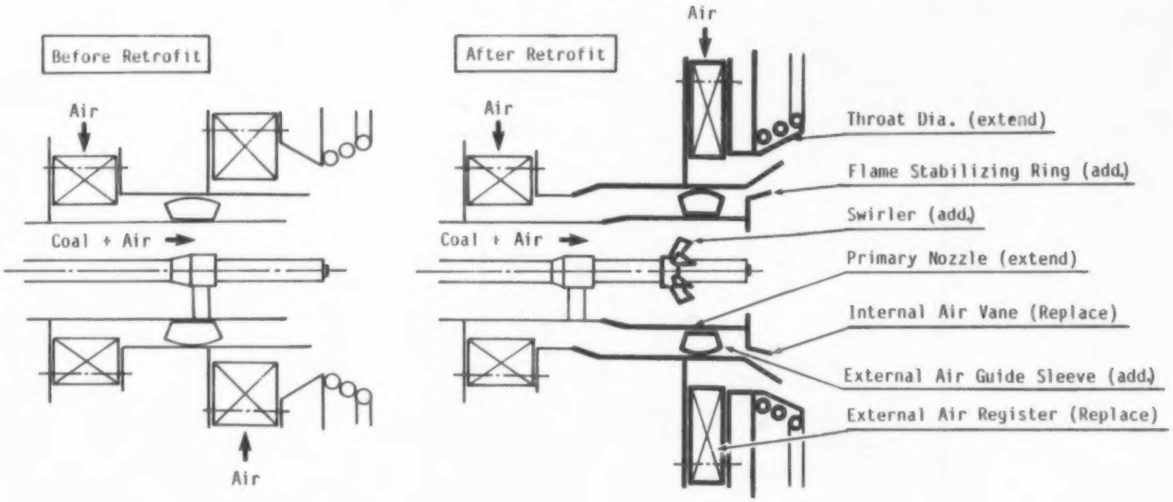

Before Retrofit
Air
Coal + Air
Air
After Retrofit
Air
Air
Coal + Air
Throat Dia. (extend)
Flame Stabilizing Ring (add.)
Swirler (add.)
Primary Nozzle (extend)
Internal Air Vane (Replace)
External Air Guide Sleeve (add.)
External Air Register (Replace)

Fig. 9 Details of Burner Retrofit

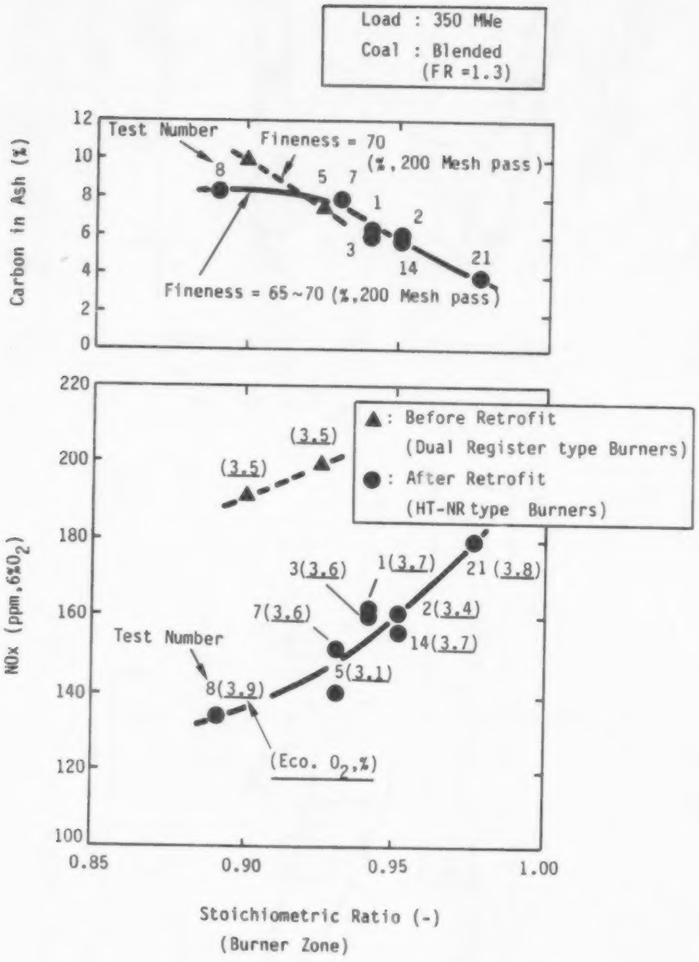


Fig. 10 NOx Emission and Carbon in Ash

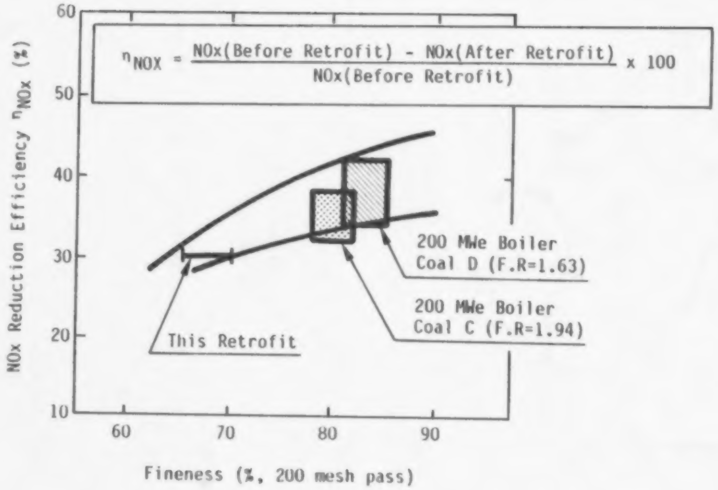


Fig. 11 NOx Reduction Efficiency Relative to Pulverized Coal Fineness

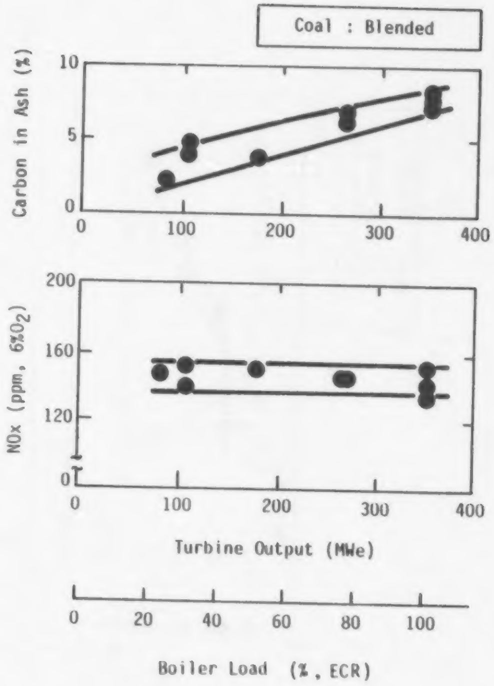


Fig. 12 NOx Emission and Carbon in Ash on each Boiler Load

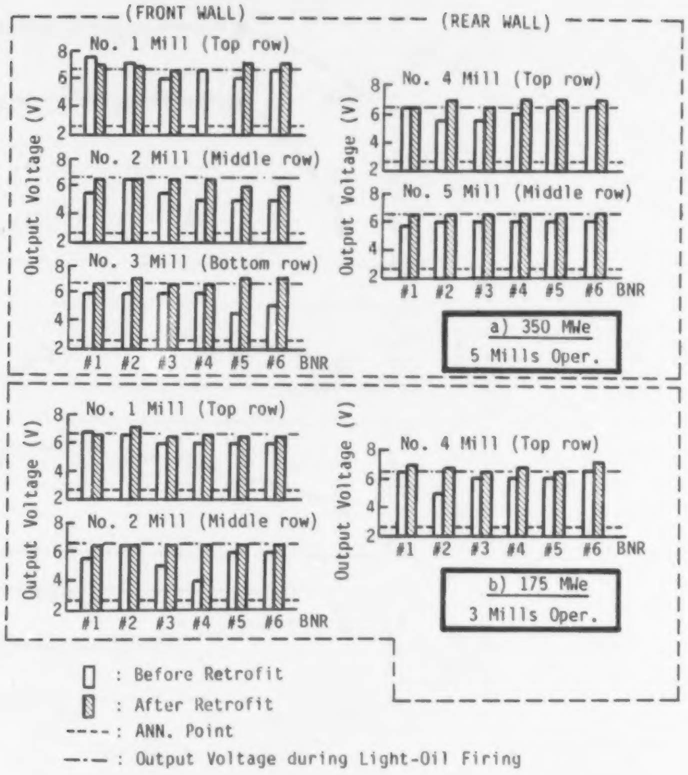


Fig. 13 Output Voltage of Flame Detectors

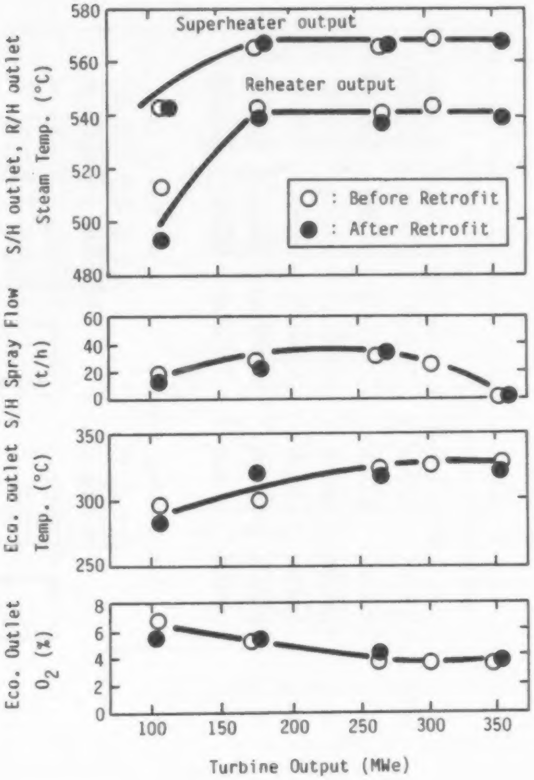


Fig. 14 Boiler Performance

Table 1

NOx Reduction Efficiency η_{NOx} (Coal-B)

Correction basis Case	Same excess air	Same UBC
I	35 ~ 40	35 ~ 40
II	35 ~ 40	< 10
III	30 ~ 40	< 10
IV	30 ~ 45	30 ~ 45
V	60 ~ 65	35 ~ 45

$$\eta_{NOx} = \frac{NOx\ (before) - NOx\ (after)}{NOx\ (before)} \times 100\ (\%)$$

Fineness : 200 mesh pass = 80 (%)

Table 2

Retrofit Items

		"before"	"after"
Turbine Output		350 MW	The same
Combustion Method		Two Stage Combustion	The same
Burner	Type	Conventional Low-NOx Burners (Dual Register type)	Modern Low-NOx Burners (Hitachi-NR type) See Fig. 9
	Arrangement	Front: 6 Bnrs x 3 Rows Rear : 6 Bnrs x 2 Rows	The same (no modification)
After-Air Ports	Type	Circular type	Dual flow type
	Arrangement	6 Ports x 1 Row,Opposed	The same

Table 3

Coal Specification during the tests

	Base	Unit	(Blended Coal)
GCV	A.D	cal/g	6,220
Moisture	W.B	%	6.6
VM	D.B	%	36.6
FC	D.B	%	47.7
Ash	D.B	%	15.7
FR (= FC/VM)	-	-	1.3
HGI	-	-	47
C	D.B	%	66.45
H	D.B	%	5.27
O	D.B	%	10.69
N	D.B	%	1.05
S (Total)	D.B	%	0.37
S (Comb.)	D.B	%	0.21
S (Uncomb.)	D.B	%	0.16

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NEW APPROACH TO NOx CONTROL
OPTIMIZATION OF NOx AND UNBURNT CARBON LOSSES

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ABSTRACT

Mitsubishi Heavy Industries, Ltd. has been engaged in the research and development of new technology concerning the prevention of air pollution. In the field of low NOx combustion technology, we have already developed and utilized many countermeasures, for example, super-low NOx PM burners, MACT system and Advanced MACT system which have already been introduced at the former symposia.

In order to offer the low cost NOx control option, MHI has developed and commercialized the method of optimizing the emission of NOx and unburnt carbon losses by controlling the fineness of pulverized coal.

This paper introduces the outline and operating experiences of the Mitsubishi low NOx PM burner (including MACT) combined with "MRS Pulverizer" which can control the fineness distribution of pulverized coal to achieve the most efficient low NOx combustion at minimum operating cost.

INTRODUCTION

The Japanese government regulation on NOx emission from thermal power plant has been amended four times since it was first introduced in 1973 and has become severer each time as shown in Figure 1. Especially in the last decade, the regulation on pulverized coal firing has been strengthened, and a low NOx level close to that of oil firing is now being required.

To control the NOx emission, MHI continuously developed and put into practical use the new low NOx firing technologies one after another as shown in Figure 2. But to achieve low NOx level with low unburnt carbon losses, relatively high initial and operating costs were required.

Low NOx pulverized coal firing technology in the 1990's will be required to accomplish the followings from the view-point of environment preservation and resources and energy saving.

- Operating economy by optimization of NOx and unburnt carbon losses.
- Establishment of low Nox firing technology for a wide variety of solid fuels such as low volatile coals and petroleum cokes.
- Realization of the above technologies at low costs.

MHI succeeded in commercializing the Advanced MACT system as the first step of new system development meeting the above need for low costs and presented it in the 1987 Synposium. As the second step, we aimed at optimizing the fineness of pulverized coal particles and succeeded in developing a new pulverizing and firing system, which consists of Mitsubishi low NOx firing technology and high-performance "MRS Pulverizer".

The new system is the most efficient, economical and flexible system that meets the future requirement for even lower NOx and unburnt carbon losses. It has already been adopted to twenty-eight boilers and has been highly rated for its superior performance.

EFFECT OF PULVERIZED COAL PARTICLE SIZE ON COMBUSTION

COMBUSTION MECHANISM OF PULVERIZED COAL

Figure 3 shows a flame model of pulverized coal burner. Pulverized coal introduced into the furnace from the coal compartment with primary air is heated by the flame and the radiant heat from high-temperature slags on furnace walls, being ignited and burnt to form the primary combustion zone. The primary combustion zone is a combustion zone of volatile matter in coal where CH_4, H_2 and CO volatilized from coal particles mix with oxygen of the primary air and form flames around the particles. The secondary combustion zone is mainly a combustion zone of char where the unburnt gas and char flowing from the primary combustion zone mix and burn with the secondary air blown in from the auxiliary air compartment.

Combustion of char is achieved by the diffusion of oxygen through the surface of char or through pores in char, and its rate of combustion is very low as compared with that of volatile matter. Therefore, the combustion time of char accounts for 80 ∿ 90% of the total combustion time of coal as also can been seen in combustion model of coal particle (Figure 4).

The points to be noted for pulverized coal combustion in the flame model of Figure 3 are ignition, burn-out and NOx emission characteristics. These characteristics are all affected by coal particle size because the speed of devolatilization and diffusion of O_2 into char are both affected by the surface area of the coal particle.

COAL PARTICLE SIZE AND BURN OUT TIME

Combustion of pulverized coal particles in a furnace can be expressed by the following equation.

$$\frac{d}{d\theta}\left(\frac{\gamma_c \pi}{6} D_p{}^3\right) = -\pi D_p{}^2 \cdot K \cdot P \qquad \text{..... (1)}$$

$$\frac{1}{K} = \frac{1}{K_c} + \frac{1}{K_f} \qquad \text{..... (2)}$$

where,

K : Overall combustion rate coefficient

K_f : Combustion rate coefficient when oxygen diffusion rate in gas boundary layer is dominant

K_c : Combustion rate coefficient when chemical reaction rate on particle surface is dominant

P : Partial pressure of oxygen

D_p : Diameter of coal particle

γ_c : Specific gravity of coal particle

θ : Combustion time

Overall combustion rate coefficient K varies greatly with coal properties as well as particle size and combustion zone gas temperature. Therefore, to keep unburnt carbon losses low, it is necessary to optimize furnace design and pulverized coal equipment to suit the characteristics of K of pulverized coal particles, coal particle diameter D_p (fineness), residence time in furnace θ, gas temperature distribution and oxygen concentration distribution in the furnace.

Figure 5 shows the unburnt carbon ratio calculated by the equations (1) and (2) above and using the calculation results of locus of flame axis and gas temperature and oxygen concentration distribution obtained by in-furnace fluid heat transfer simulation. At a height about 5 meters above the burner toward furnace outlet, combustion progresses rapidly, but becomes slow around 10 meters, and hardly progresses over 20 meters because of decrease in gas temperature. This indicates thatreduction in coal particle diameter by improving the fineness is more effective to increase combustion efficiency of pulverized coal than lengthening residence time in the furnace.

COAL PARTICLE SIZE VS. NOx AND UNBURNT CARBON

In order to confirm the effect of coal particle size on NOx and unburnt carbon losses, combustion test has been conducted in MHI Laboratory. Pulverized coal were classified into seven groups of different particle sizes and fired separately in 2 kg/h basic combustion test furnace shown in Figure 6.

The test results are shown in Figures 7 to 9 and the properties of the coals used for the tests are shown in Table 1. As seen from Figures 7 and 8, NOx emissions increase with an increase in particle size and unburnt carbon considerably increases when particle size becomes larger than 100 mesh. This indicates that removing coarse particles larger than 100 mesh (150 μ) is very effective in reducing unburnt carbon losses.

PARTICLE DIAMETER AND IGNITION STABILITY

Figure 9 shows the relation between particle diameter and ignition distance. As can be seen in this Figure, the smaller the particle diameter the smaller the ignition distance. However, making particle diameter smaller than 200 mesh produces little effects.

SUMMARY

Increasing fineness is effective for all of the followings.

- Reduction in unburnt carbon losses
- Reduction in NOx emission
- Improvement in ignition stability

EFFECT OF FINENESS ON CONVENTIONAL PULVERIZER

Pulverized coal fineness of a conventional pulverizer with a fixed type separator is normally 70 ∿ 80% through 200 mesh and generally more than 5% residue on 100 mesh. Attempt to improve fineness to reduce unburnt carbon losses involves the following problems.

- High Vibration
  High fineness operation increases the amount of recirculated load in the mill and make the coal on the grinding table finer to make the roll to slip and cause very high vibration.
- Remarkable decrease in mill capacity
  Capacity decreases by 25% to reduce 100 mesh residue to half.
- Remarkable increase in power consumption
  Power consumption increases by 30% to reduce 100 mesh residue to half.
- Remarkable increase in primary air to coal ratio
  For the same mill throughput, a larger size mill with higher air requirement must be selected. Therefore primary air to coal ratio increases by 30% to reduce 100 mesh residue to half.

Therefore about 80% of through 200 mesh had been considered to be the practical limit for conventional pulverizers and 100 mesh residue could not be reduced below approx. 3%.

For these reasons, all the mills MHI delivered before 1985 were designed for pulverized coal fineness of below 80% through 200 mesh as shown in Figure 10. Development and commercialization of "MRS Pulverizer" has totally changed this concept and has realized the economical operation of higher than 85% through 200 mesh.

DEVELOPMENT OF HIGH PERFORMANCE "MRS PULVERIZER"

In order to realize the most effective and economical low NOx combustion by optimizing the coal particle size distribution, MHI has developed "MRS Pulverizer".

CONSTRUCTION AND OPERATING PRINCIPLE OF "MRS PULVERIZER"

"MRS Pulverizer" is, as is shown in Figure 11, equipped with a "Mitsubishi Rotary Separator" of forced rotation type instead of a conventional cyclone separator of fixed type and its structure and operating principle is as follows.

Raw coal, which is fed through the coal feed pipe onto a rotating bowl, is centrifugally transferred to the outer circumference of the bowl. The coal is then introduced between a roll and a bullring segment, which lines the bowl, and ground. Grinding load is applied to the roll by means of a hydraulic cylinder or a spring. The pulverized coal is carried up to the upper part of the mill by hot air, which flows from the outer circumference of the bowl.

In its upper part, the mill is equipped with a rotary separator, which performs centrifugal and impinging classification by means of rotating vanes. The coarse particles are separated from fine particles and fall onto the bowl to be reground. After passing through the rotary separator, the fine powder of required size is carried into a pulverized coal pipe through an outlet port.

CLASSIFYING PRINCIPLE OF "MRS PULVERIZER"

The classifying principle of "MRS Pulverizer" can be simply explained as follows (Figure 12). Crushed in the grinding and drying chamber, coal particles are pneumatically carried into the separator, where the particles impinge against the rotating separator vanes, and according to the balance of forces within a separating zone, only fine particles enter the inside, whereas the coarse are ejected away towards the outside. The coal particles existing in this separating zone are under the influence of centrifugal (F) and centripetal (R) forces caused by the separator vanes and the air flow respectively.

It can be theoretically said that coal particles are ejected out of the separator for F > R and they enter into the separator for F < R. F and R are expressed by following equations when a particle is assumed as sphere.

$$F = \frac{\pi}{6} D_p{}^3 (\rho - \rho_a) \frac{\nu_\theta{}^2}{\gamma} \quad \ldots\ldots (3)$$

$$R = C_D \frac{\pi}{4} D_p{}^2 \frac{\rho_a \nu_r{}^2}{2} \quad \ldots\ldots (4)$$

where,

D_p : Diameter of coal particle

ρ, ρ_a: Density of particle and air

ν_θ : Rotational speed of vanes

ν_r : Radial velocity of air

γ : Rotational radius of vanes

C_D : Coefficient of resistance

Figure 13 shows the values of F and R when particle diameter "D_p" is varied. Value of "D_p" at the intersection of two lines, or when F=R, is called theoretical classification diameter.

In order to optimize the design of "MRS Pulverizer", transparent model shown in Figure 14 was used to visually investigate the classifying phenomena at the vanes as well as the series of actual grinding tests by 3 t/h test mill in MHI Research and Development Center.

PERFORMANCE OF "MRS PULVERIZER"

Following three outstanding features of "MRS Pulverizer" have been confirmed as a result of actual operation.

- Extremely high fineness

Due to the optimum design of rotary separator, such a high fineness as more than 95% through 200 mesh can be obtained without high vibration, an example of operation results being shown in Figure 15. If separator RPM is adjusted, operation can be made without any problem even at 100% through 200 mesh.

- Effective classification of coarse particles

Figure 16 shows the relationship between the amounts of through 200 mesh and residue on 100 mesh of pulverized coal. Residue on 100 mesh in a "MRS Pulverizer" is reduced to less than one-fifth of that in a corresponding conventional. As can be seen in Figure 16, residue on 100 mesh can even be reduced to zero if through 200 mesh is adjusted at higher than 90%.

- High capacity and lower power consumption

Due to the effective and sharp classification capability of "MRS Pulverizer", recirculated load in the mill has been considerably reduced. Therefore for the same fineness, capacity of "MRS Pulverizer" is higher and power consumption is lower compared with conventional pulverizer as shown in Figures 17 and 18.

LABORATORY COMBUSTION TEST RESULT

In order to compare the combustion characteristics of pulverized coals prepared by "MRS Pulverizer" with that of conventional pulverizer, following two kinds of laboratory combustion tests have been performed.

COMBUSTION TEST IN 2 kg/h BASIC COMBUSTION TEST FURNACE

Test Conditions

Pulverized coals of different fineness level have been prepared by both type of pulverizers, MRS and conventional, and tested in 2 kg/h basic combustion test furnace shown in Figure 6. Property of the coal used for the test is shown in

Table 2. Pulverized coal fineness distribution for each test is as shown in Figure 19.

Test Results

Test results are summarized in Figures 20 to 21. Following conclusions can be derived from the Figures.

- For the same excess O_2 level, NOx and unburnt carbon losses of MRS pulverized coal are both lower than that of conventional mill.
- Unburnt carbon losses are approximately proportional to residue on 100 mesh for the same excess O_2.

COMBUSTION TEST IN 1.5 t/h TEST FURNACE

Test Condition

In order to re-confirm the result of 2 kg/h test, additional larger scale combustion test has been conducted in 1.5 t/h test furnace shown in Figure 22. The properties and fineness of the coals used for the test are shown in Table 3.

Test Result

Test results are summarized in Figures 23 and 24. Following conclusions can be derived from the Figures.

- For the same excess O_2, "MRS Pulverizer" can achieve approx. 40% lower unburnt carbon losses.
- For the same excess O_2, "MRS Pulverizer" can achieve approx. 15 ppm lower NOx emission.
- For the same unburnt carbon losses, "MRS Pulverizer" can achieve approx. 35% lower excess O_2 and 30 to 35% lower NOx emission.

APPLICATION OF "MRS PULVERIZER" TO LOW NOx BURNERS

DESCRIPTION OF BOILERS

Low NOx combustion system with "MRS Pulverizer" has been adopted in twenty-eight boilers, of which twenty have already been in operation successfully.
Names of plants, burner type and fuel used are shown in Table 4.

OPERATION RESULTS

Figure 25 shows the comparison of unburnt carbon losses of "MRS Pulverizers" and conventional pulverizers at various plants. It can well be said that unburnt carbon losses were successfully reduced to one-third to one-fourth with the use of "MRS Pulverizer".

Figure 26 shows the relationship of NOx emission and unburnt carbon losses for both type pulverizers. For the same unburnt carbon losses, NOx emission has been reduced by approx. 50% with "MRS Pulverizer".

OPTIMIZATION OF NOx AND UNBURNT CARBON LOSSES

From the above operation result, NOx emission and unburnt carbon losses had been both reduced by the application of low NOx combustion system with "MRS Pulverizer". It is most remarkable that above improvement has been accomplished with reduction of auxiliary power consumption as shown in Figure 27.

RETROFIT TO "MRS PULVERIZER"

One of the most remarkable advantage of the low NOx firing system with "MRS Pulverizer" is that the existing mills can be easily converted to "MRS Pulverizer" to achieve the optimization of NOx and unburnt carbon losses at minimum modification cost.

RETROFIT PROCEDURES TO "MRS PULVERIZER"

Conventional mills with cyclone type separator can be easily converted to "MRS Pulverizer" simply by replacing the existing separator with "Mitsubishi Rotary Separator" as shown in Figure 28.

MERIT OF RETROFIT

Figure 29 shows the merit of modifying existing mills to "MRS Pulverizers" for 500 MW coal fired unit now under study. Merit of modification is 50% reduction of NOx emission together with $ 736 THOUSAND annual saving by improved combustion efficiency and reduced auxiliary power consumption including mill, IDF and FDF.

CONCLUSION

The low NOx burner system with "MRS Pulverizer" is one of the most innovative technology which MHI has developed and commercialized on her own. The technology has already been adopted in many plants including in Belgium, China and Hongkong as well as in Japan and we are sure that it will be able to fully meet the environmental requirement of all countries of the world in the future.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

REFERENCES

1. Araoka, M., et al., Application of Mitsubishi "Advanced Mact" In-furnace NOx Removal Process at Taio Paper Co., LTD. Mishima Mill No.18 Boiler, March 1987.

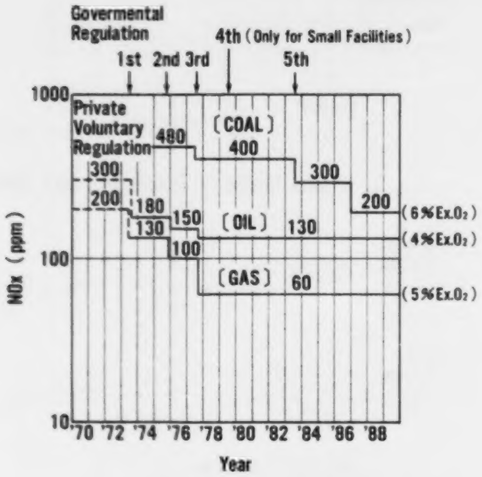

Fig. 1 Trend of Governmental Regulation on NOx Emission for New Large Plants in Japan

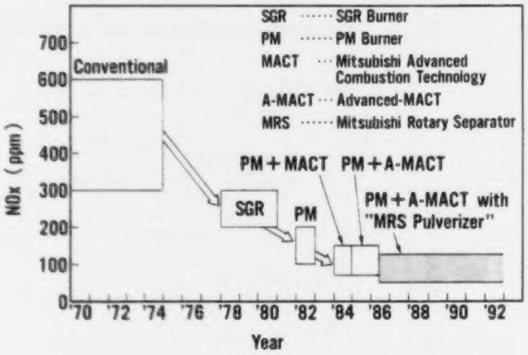

Fig. 2 History of Low NOx Technology for Pulverized Coal Fired Boilers

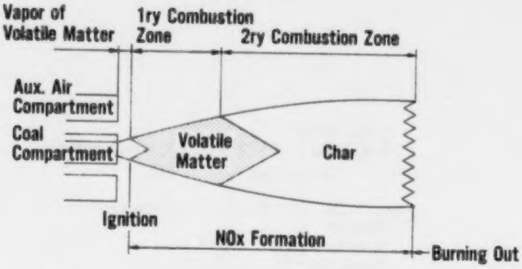
Vapor of Volatile Matter
1ry Combustion Zone
2ry Combustion Zone
Aux. Air Compartment
Coal Compartment
Volatile Matter
Char
Ignition
NOx Formation
Burning Out

Fig. 3 Flame Model of Pulverized Coal Burner

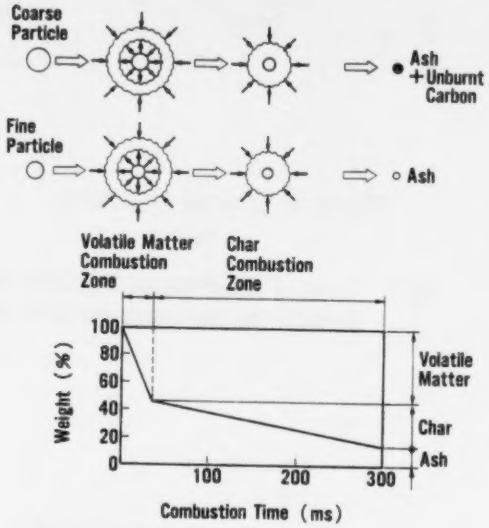
Coarse Particle
Ash + Unburnt Carbon
Fine Particle
Ash
Volatile Matter Combustion Zone
Char Combustion Zone
100
80
60
40
20
0
Weight (%)
100
200
300
Combustion Time (ms)
Volatile Matter
Char
Ash

Fig. 4 Combustion Model of Coal Particle

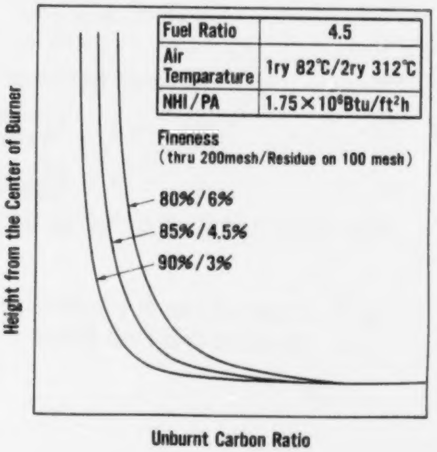

Fig. 5 Relation between Fineness and Unburnt Carbon

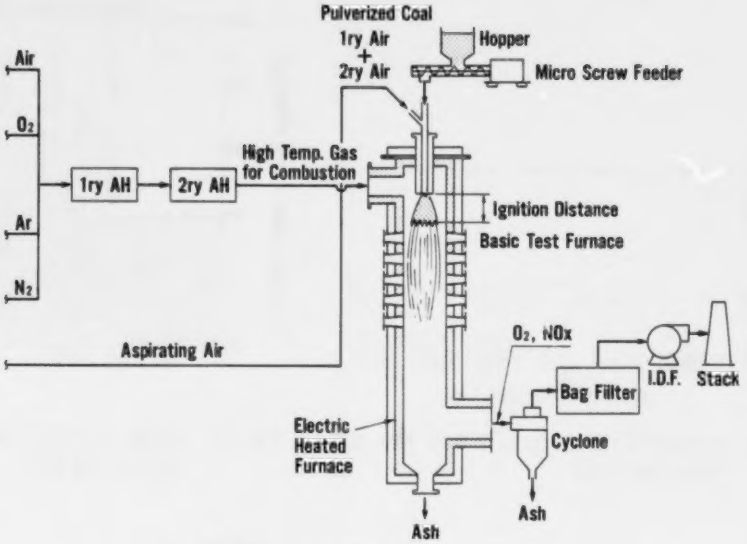
Pulverized Coal
1ry Air
+
2ry Air
Hopper
Micro Screw Feeder
Air
O₂
Ar
N₂
1ry AH
2ry AH
High Temp. Gas for Combustion
Ignition Distance
Basic Test Furnace
Aspirating Air
O₂, NOx
Bag Fillter
I.D.F.
Stack
Electric Heated Furnace
Cyclone
Ash
Ash

Fig. 6 2kg/h Basic Test Furnace

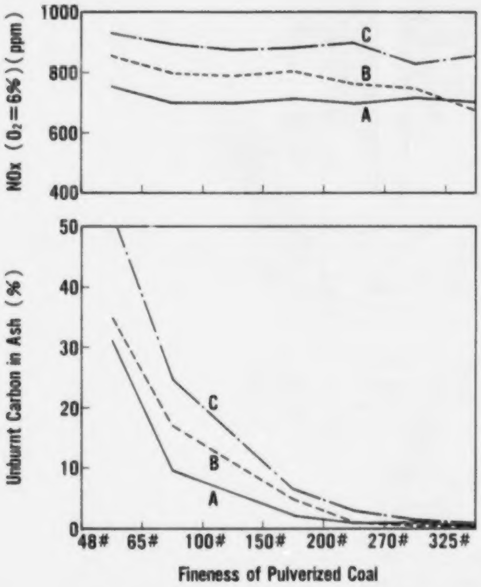

Fig. 7 Coal Particle Size vs. NOx, Unburnt Carbon

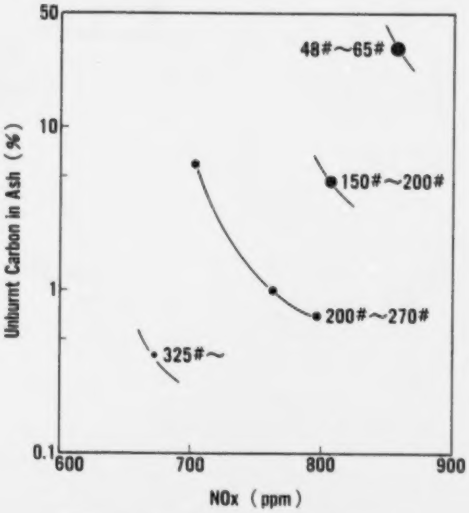

Fig. 8 NOx vs. Unburnt Carbon in Ash

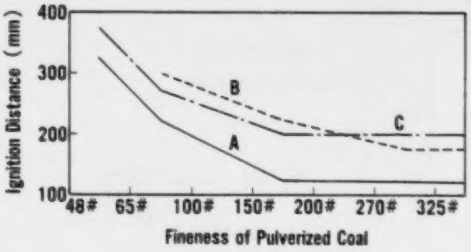

Fig. 9 Ignition Distance and Particle Size of Pulverized Coal

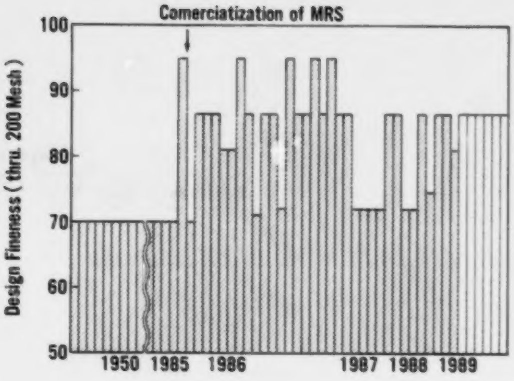

Fig. 10 Trend of Design Fineness of Pulverizers Supplied by MHI

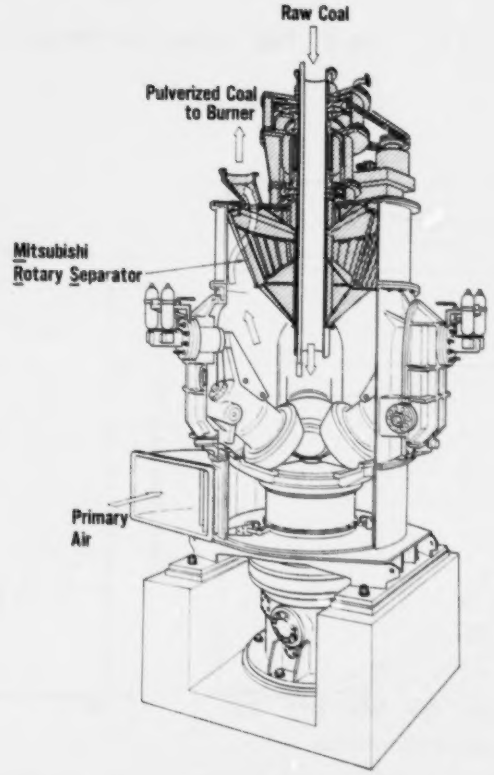
Raw Coal
Pulverized Coal to Burner
Mitsubishi Rotary Separator
Primary Air

Fig. 11 Construction of MRS Pulverizer

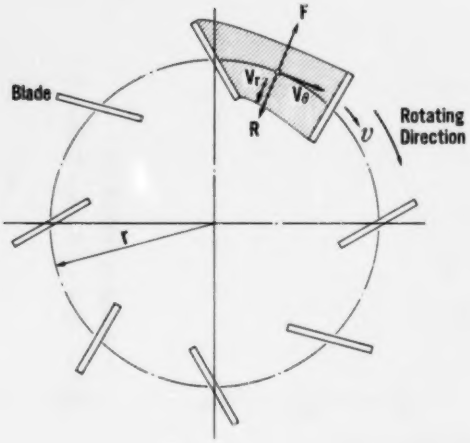
F
Blade
V_r
V_θ
R
v
Rotating Direction
r

Fig. 12 Classifying Principle of MRS Pulverizer

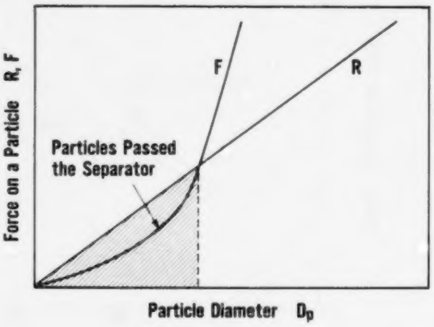

Fig. 13 Theorical Classification Diameter

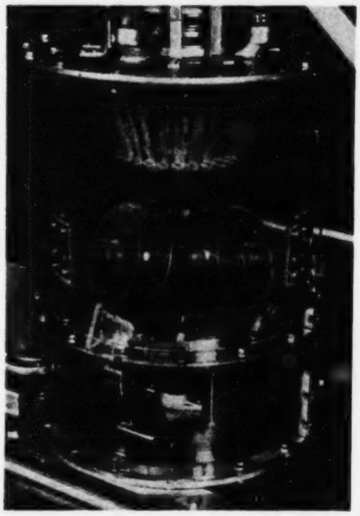

Fig. 14 Transparent Model of MRS Pulverizer

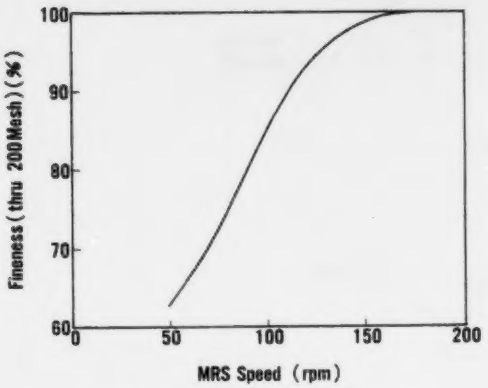

Fig. 15 MRS Speed vs. Fineness

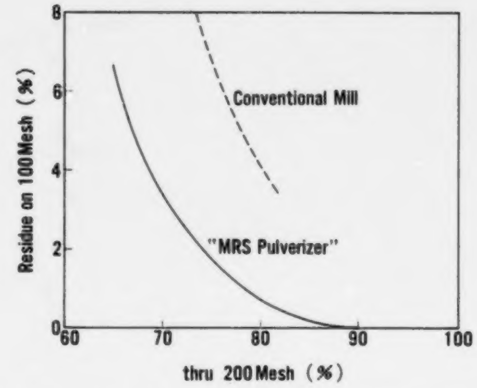

Fig. 16 Thru 200Mesh and Residue on 100Mesh

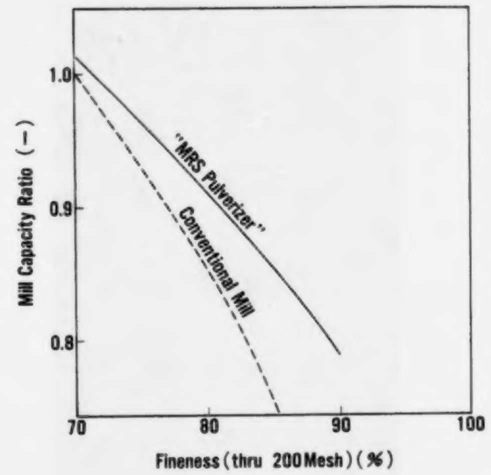

Fig. 17 Fineness vs. Mill Capacity

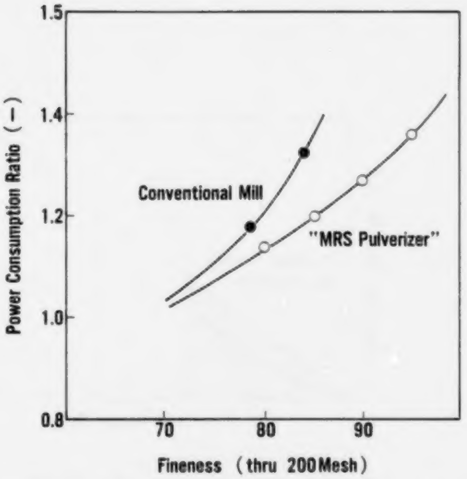

Fig. 18 Fineness and Mill Power Consumption

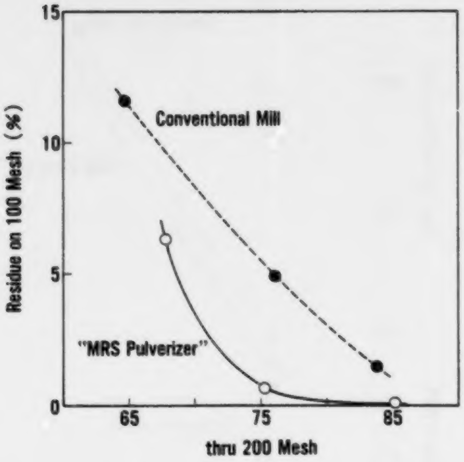

Fig. 19 Fineness Distribution of Coals Tested

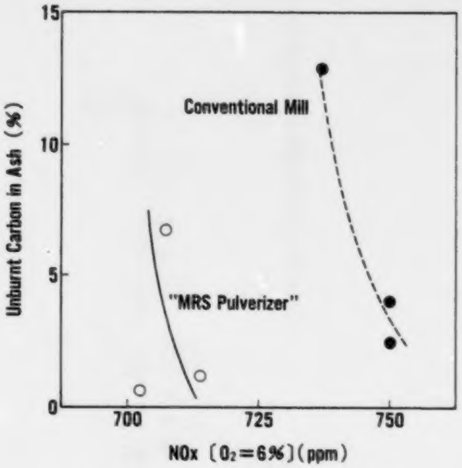

Fig. 20 NOx and Unburnt Carbon

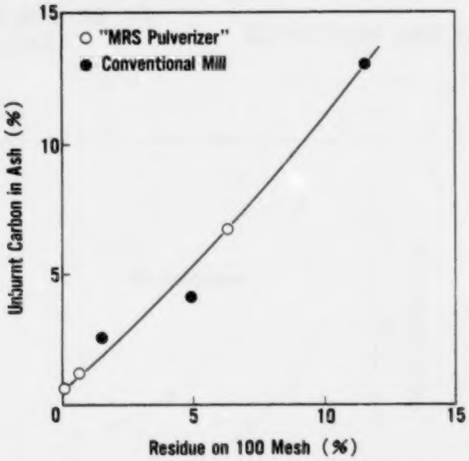

Fig. 21 Residue on 100 Mesh vs Unburnt Carbon in Ash

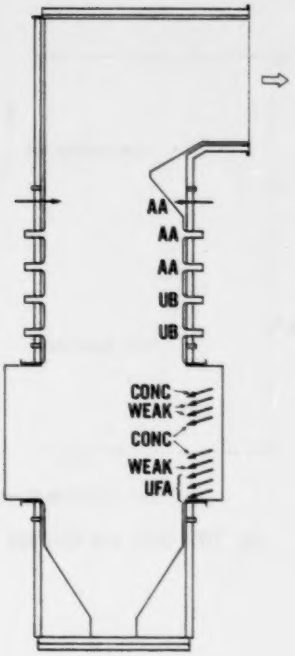
AA
AA
AA
UB
UB
CONC
WEAK
CONC
WEAK
UFA

Fig. 22 1.5t/h Coal Firing Test Furnance

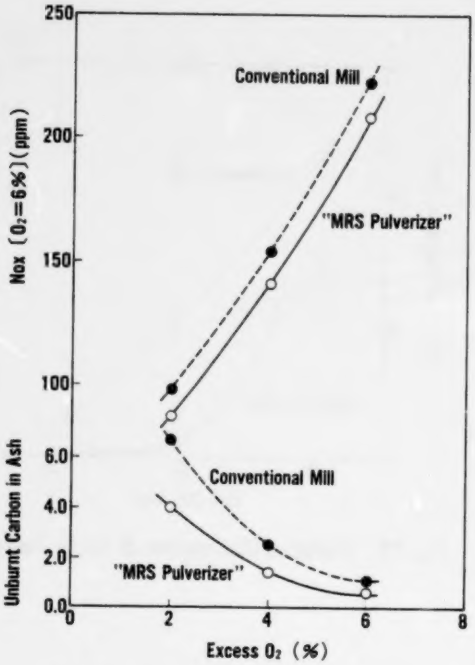

Fig. 23 NOx and Unburnt Carbon in Ash vs Excess O_2

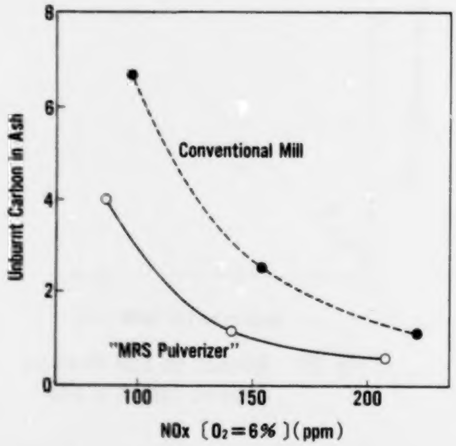

Fig. 24 NOx and Unburnt Carbon in Ash

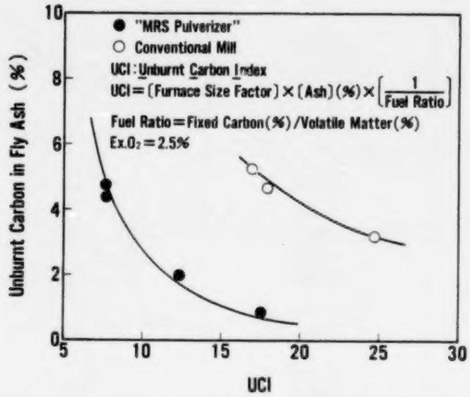

Fig. 25 Mill Type and Unburnt Carbon in Ash

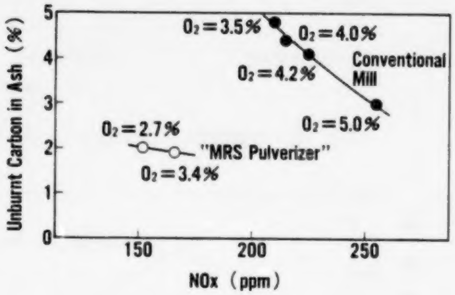

Fig. 26 NOx, Unburnt Carbon in Ash and Mill Type

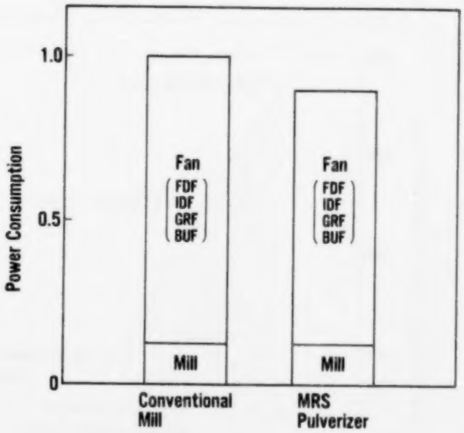

Fig. 27 Decrease of Power Consumption by Adoption of "MRS Pulverizer"

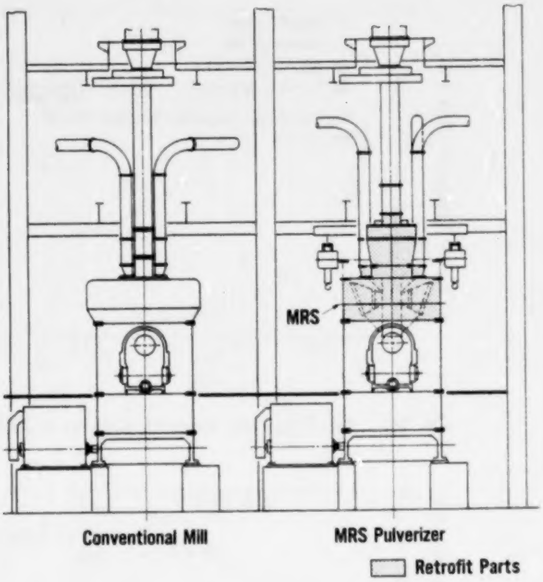
MRS
Conventional Mill
MRS Pulverizer
▭ Retrofit Parts

Fig. 28 Retrofit Procedure to MRS

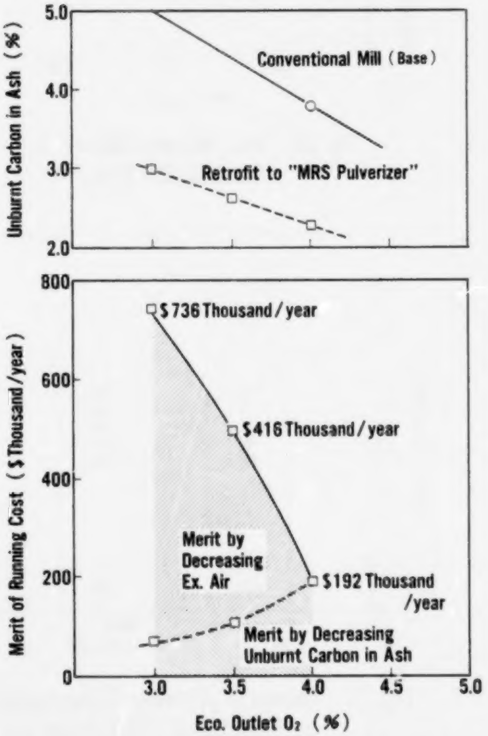

Fig. 29 Merit of Retrofit to "MRS Pulverizer"

Table 1 Coals Used for Particle Combustion Test

	Item \ Coal Kind	A	B	C
	Heating Value (kcal/kg) (HHV-S-M Free)	5780	6620	6650
Proximate Analysis	Surface Moisture (%)	1.9	3.4	7.0
	Inherent Moisture (%)	5.4	5.3	3.4
	Fixed Carbon (%)	33.2	56.0	61.6
	Volatile Matter (%)	41.2	27.2	19.4
	Ash (%)	20.2	11.5	15.6
Ultimate Analysis	C (%)	61.6	74.2	73.6
	H (%)	5.3	4.2	3.8
	O (%)	10.6	8.3	5.4
	N (%)	0.90	0.81	0.99
	S (%)	0.19	0.55	0.25

Table 2 Test Coal Analysis

HHV (kcal/kg)	Inherent Moist. (%)	Fixed Carbon (%)	Volatile Matter (%)	Ash (%)	S (%)
6812	6.3	57.4	29.2	7.1	0.48

Table 3 Coal Used for 1.5t/h Combustion Test

Mill Type	Fineness		Proximate Analysis (%)				HHV (kcal/kg)
	thru 200Mesh (%)	Residue on 100Mesh (%)	Inherent Moist.	Fixed Carbon	Volatile Matter	Ash	
MRS	75.3	0.65	6.3	57.4	29.2	7.1	6812
Conventional	76.1	4.9					

Table 4 Supply List of Low NOx Burner with "MRS Pulverizer"

Fuel	Plant Name	Boiler Capacity	Mill Type	Mill Capacity (t/h)	Numbers Furnished	Start of Commercial Operation	Actual Result of Coal Fineness (%)		Low NOx Technology
							Residue on 100 Mesh	Through 200 Mesh	
Coal	Kanebo Co., Ltd. Hofu Factory	130t/h	523RP -MRS	7.1	2	Aug. 1985	1.2	83.6	A-MACT
	Asahi Chemical Co., Ltd. Nobeoka Factory #3 Unit	160t/h	643XRP -MRS	15.0	2	Apr. 1986	0	96	A-MACT
	Taio Pulp Co., Ltd. Mishima Factory #18 Unit	350t/h	703RP -MRS	17.6	4	Apr. 1986	0	89	A-MACT
	Teijin Co., Ltd. Tokuyama Factory	80t/h	483RP -MRS	6.1	2	Apr. 1986	0	88	A-MACT
	Ehime Paper MFG. Iyomishima Factory	95t/h	523RP -MRS	7.2	2	May 1986	0.8	86.2	A-MACT
	Showa Sangyo, Ltd.	70t/h	463XRP -MRS	7.2	2	Aug. 1986	0.2	86.4	A-MACT
	Teijin Co., Ltd. Mihara Factory	130t/h	563RP -MRS	9.0	2	Sep. 1986	0	88	A-MACT
	Idemitsu Engineering Co., Ltd.	130t/h	563XRP -MRS	9.7	2	Oct. 1986	0.4	87	A-MACT
	Kanegafuchi Chemical Co., Ltd Takasago Factory	270t/h	623RP -MRS	10.4	3	Apr. 1987	0.2	90.9	A-MACT
	Matsuda Co., Ltd.	110t/h ×2	523RP -MRS	8.1	4	Sep. 1987	0.4	83	A-MACT
	Chubu Electric Power Co., Ltd. Test Plant	15t/h	303RP -MRS	1.7	1	Sep. 1987	0.1	87	A-MACT
	China Huangtai P/S #7 Unit	300MW	863XRP -MRS	42.5	5	Oct. 1987	0.3	86.4	OFA
	Maruzumi Paper MFG. OOE Factory	210t/h	623RP -MRS	9.2	2	Jun. 1988	0	85	A-MACT
	Daiseru Aboshi Co., Ltd.	300t/h	623RP -MRS	12.9	3	Apr. 1989	—	—	A-MACT
	Taio Pulp Co., Ltd. Mishima Factory #19 Unit	350t/h	703RP -MRS	17.6	4	Apr. 1989	—	—	A-MACT
	Banyu Shibiyo, Ltd.	140t/h	603RP -MRS	9.0	2	Oct. 1989	—	—	A-MACT
	Hokuriku Electric Power Co., Ltd. Tsuruga P/S #1 Unit	500MW	943RP -MRS	41.7	6	Oct. 1991	—	—	A-MACT
	Chubu Electric Power Co., Ltd. Hekinan P/S #1 Unit	700MW	1103RP -MRS	82.5	6	Oct. 1991	—	—	A-MACT
	Chang Chun Petrochemical Co., Ltd.	210t/h	623RP -MRS	14.0	2	Jul. 1989	—	—	A-MACT
	Hong Kong Electric Co., Ltd. Lamma P/S #6 Unit	350MW	903RP -MRS	40.6	5	Apr. 1991	—	—	OFA
Petro. Coke	Mitsubishi Acetate Co., Ltd. Toyama Factory	75t/h	563RS -MRS	7.8	1	Sep. 1985	0	98	A-MACT
	Toho Rayon Co., Ltd. Tokushima Factory	75t/h	483RS -MRS	3.2	1	Nov. 1985	0	96.5	A-MACT
	Sumitomo Chemical Co., Ltd. Chiba Works	305t/h	583RS -MRS	8.7	2	Dec. 1985	0	98.9	OFA
	Toyo Pulp Co., Ltd. Kure Factory	80t/h	563RS -MRS	9.5	1	Jun. 1986	0	96	OFA
	Mitsubishi Chemical Co., Ltd. Mizushima Factory	170t/h	483RP -MRS	4.8	1	Sep. 1986	0	93	A-MACT
	Takeda Chemical Industries, Ltd.	100t/h	563RS -MRS	6.8	1	Oct. 1986	0	96	A-MACT
Coal / Petro. Coke	Mitsubishi Rayon Co., Ltd. Ootake Factory	180t/h	583RP -MRS	11.5/8.2	2	Apr. 1989	—	—	A-MACT

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THE XCL BURNER - LATEST DEVELOPMENTS AND OPERATING EXPERIENCE

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ABSTRACT

As reported at the previous symposium in New Orleans, B&W developed the XCL burner to further reduce NO_x emissions from wall-fired, pulverized coal boilers. A full complement of XCL burners was installed at Ohio Edison's Edgewater Station, Unit 4, as a key element of the LIMB demonstration. Optimization in this application required implementation of corrective measures to other boiler systems, including the air heater and pulverizer feeder controls. NO_x emissions well under New Source Performance Standards with high combustion efficiency were subsequently demonstrated.

B&W's XCL burner is being applied commercially to utility and industrial size units. A recent contract included the development and use of the XCL Tri-Fuel burner, capable of firing natural gas, fuel oil, or pulverized coal. The development included extensive testing on one full-scale prototype burner (120 million Btu/hr) on all three fuels. Fuel-staging technology incorporated in the XCL resulted in NO_x emissions less than: 0.1 (lb/million Btu) with gas; 0.2 with No. 6 oil; and 0.35 with high and low volatile bituminous coal. These results were obtained without use of other NO_x control measures such as gas recirculation and NO_x ports. However, even lower emissions were achieved in combination with these measures. Consequently, B&W has designed the XCL Oil/Gas burner for use in low NO_x applications with these fuels. Most recently, B&W developed the XCL-FM for low NO_x applications in package boilers with unheated combustion air. Testing in such a boiler at B&W's Alliance Research Center has demonstrated NO_x emissions less than 0.1 for natural gas and distillate oil (burner only) and less than 0.04 with gas recirculation.

INTRODUCTION AND BACKGROUND

In 1985 Babcock & Wilcox (B&W) embarked on a program to develop a true second generation low NO_x burner for firing pulverized coal. The motivation for this program was to address a changing marketplace in the United States. New utility and industrial boilers have increasingly been regulated to NO_x emission limits much below federal New Source Performance Standards (NSPS). Furthermore, many pre-NSPS units are likely to be subject to NO_x limitations in the near future. These circumstances increase the need for combustion equipment which can efficiently reduce NO_x emissions while being adaptable to existing boilers.

Combustion equipment, being the source of NO_x, is most often the first choice for control of NO_x emissions. B&W's Dual Register Burner (DRB) has proven to be very effective in controlling NO_x in new wall-fired utility boilers. All of the 68 units in service with DRB's are satisfying applicable NSPS NO_x limitations (1). This 100 percent record has been achieved without the need for alterations to reduce NO_x during the commissioning of any of these units. And unlike other manufacturers, this performance is achieved by virtue of the burner performance and without augmentation by overfire air ports, underfire air ports, boundary air, etc. This procedure avoids problems with slagging and corrosion in the combustion zone associated with air staging.

However, the DRB is difficult to apply to pre-NSPS boilers. One reason for the DRB's success in control of NO_x is its use in combination with compartmented windboxes (Figure 1). Efficient combustion with low NO_x is dependent on properly distributed air and fuel for the combustion system. The compartmented windbox enables reliable control of secondary air to the burners served by each pulverizer. However, retrofitting compartmented windboxes to existing boilers can be complicated and expensive, owing to burner layout, space limitations, etc. Still the need remains for an accurate and reliable means of distributing and controlling secondary air, which should be addressed by the new burner design.

In addition, the burner must perform well within the confines of pre-NSPS boiler designs. NO_x reduction has to be achieved in the more compact furnaces characteristic of these units. This requirement is complicated by the higher thermal loading to the combustion zone tending to increase NO_x, and smaller furnace dimensions which sometimes constrain flame shape and NO_x (air/fuel mixing restrictions). And, at least equally important, the burner must be mechanically reliable in the hostile operating conditions for which it is intended. Mechanical breakdowns not only add to expense in time and material to repair, but also can impair boiler performance (slagging) and cause load restrictions.

B&W designed a new burner called the XCL (aXial-Controlled-Low NO_x burner) to address these issues. The XCL (Figure 2) combines features from three commercially successful burners, drawing on their experience and demonstrated performance. Then, some features were added to the XCL which uniquely enhanced its performance. The functional design of the XCL is largely derived from B&W's DRB, and from Babcock Hitachi's HT-NR burner via licensed technology (2). Fuel dispersion is achieved in the nozzle by the conical diffuser, resulting in a fuel-rich ring near the walls of the nozzle and a fuel- lean core. The fuel exits through a flame stabilizing ring which accelerates ignition and devolatilization. Reducing species then form by partial oxidation of coal volatiles from primary air and limited secondary air. The reducing zone in the core of the flame prevents NO_x formation during devolatilization, and the reducing species generated serve to decompose NO_x as the combustion continues into the char oxidation phase. Multistage air vanes and the air separation vane limit burner pressure drop, improve distribution of secondary air within the burner and, consequently, provide more uniform swirl patterns leaving the throat and control of near field stoichiometry and downstream mixing. An impeller is used, when appropriate, to vary flame shape with some trade-off in NO_x emissions. The mechanical configuration is adapted from B&W's S-type burner. The S-burner's success commercially has come from demonstrated combustion improvements and mechanical reliability when retrofitted to pre-NSPS boilers. Like the S-burner, the XCL uses a slide damper to reliably control secondary air and is equipped with a pitot grid downstream of the burner entrance to measure secondary air flow in each burner. These measurements are used during commissioning to identify air distribution patterns in the windbox to enable balancing air flow to each burner. The rugged stainless steel construction has solved problems with overheating, warpage, binding, etc., experienced by other burners.

Development of the XCL burner began with prototype-scale, 78 million Btu/hr (MKB) tests to evaluate and tune secondary air flow patterns relative to tests performed on a DRB and HT-NR. Flow testing was followed by extensive combustion tests, as reported previously (3). These tests, performed with support by the EPA, confirmed the XCL burner could meet performance criteria stipulated for the low NO_x burners to be used on the Limestone Injection Multistage Burner (LIMB) project. By use of a modified impeller, flame shape could be varied to accommodate the furnace dimensions. Flame length could be varied from 12 to 22 feet, with NO_x emissions varying from 0.6 to 0.3 lb/MKB (unstaged). Burner resistance was near 4 inch w.c. and carbon in the ash was 2-3 percent firing Pittsburgh 8 coal.

XCL BURNER UTILITY BOILER RETROFIT

B&W fabricated and installed 12 XCL burners at Ohio Edison's Edgewater Station, Unit 4, as a key aspect of the LIMB project. This unit has a B&W natural circulation boiler rated at 690,000 lb/hr main steam flow at 1480 psig/1000°F (Figure 3). Prior to XCL burner installation, baseline tests were performed on the unit with the existing circular burners. After burner tuning, full load NO_x emissions were 0.89 lb/MKB, with 20 ppm CO, 3 percent excess O_2 at the burners, and averaged 2.2 percent carbon in the ash (Table 1).

The XCL burners were installed during the fall of 1986. As installed, the XCL's reduced NO_x to 0.53 lb/MKB at full load and 3-3.5 percent excess O_2 at the burners, with 115 ppm CO and with 2.8 percent carbon in the ash. Flame lengths were 15-18 feet, well short of the rear wall (22 ft. furnace depth). NO_x was reduced by 40 percent while maintaining high combustion efficiency.

Burner characterization/optimization testing followed, with plans to reduce NO_x below the 0.5 lb/MKB program goal by making use of flame shaping features of the XCL. Impeller adjustments reduced NO_x to 0.34 to 0.40 lb/MKB, but CO and unburned carbon (UBC) increased unexpectedly to unacceptable values. Furnace gas specie probing at the entrance to the superheater identified zones deficient in oxygen, which explained the high CO/UBC. Note that air flow readings from the XCL burner pitot grids did not support the furnace O_2 distribution, and raised suspicion of fuel distribution among burners. Burner dampers could be tuned to improve furnace O_2 distribution and sharply reduced CO, e.g. from 2500 to 75 ppm average leaving the boiler. Conical diffusers were installed in three of the burner elevations to retain low NO_x performance, but problems continued with CO and UBC. Continued furnace probing and investigation showed the O_2/CO patterns leaving the furnace changed considerably from day to day, while burner settings, load, and excess air were unchanged. The unexplained variations in air/fuel distribution prevented implementation of "fixes" to balance and tune the system. Fuel distribution and loading of the pulverizers was identified as the main problem. The control system for regulating primary air and coal to these pulverizers has no direct measure of coal flow to the mills. The table feeders provide neither a volumetric or weight flow indication of coal. In addition, the pneumatic controllers were subject to maladjustment and loss of calibration. The combined result was non-repeatable and non-uniform coal feed to the four pulverizers, and varying coal distribution leaving each of the pulverizers. The mill serving the second from top burner elevation contributed disproportionately to the CO/UBC problems so impellers were reinstalled in those burners to reduce sensitivity to fuel problems. Combustion was also impaired by marginal excess air. While the XCL pressure drop met the program's 5 inch w.c. limit at MCR, the burner resistance had increased about 3 inches over the circular burners. This increase, combined with continuing air heater leakage limited excess air to 3-3.5 percent at full load, or lower, depending on operating conditions. While this excess air level is reasonable with good air/fuel distribution, it did little to compensate for fuel flow variations.

Optimization work eventually resulted in NO_x being reduced to just under the 0.5 lb/MKB program goal, i.e. to 0.47, with 6 percent carbon in ash and 60 ppm CO (full load normal excess air). New solid state feeder controls were installed late in 1988 and are expected to improve fuel control with the table feeder and reduce carbon in the ash after tuning.

This burner retrofit program showed the importance of accurate fuel/air control to low NO_x combustion optimization. Inaccuracies in air/fuel distribution and control may not cause significant combustion inefficiencies with pre-NSPS rapid mix burners. This circumstance was true for the circular burners at this plant. In addition, the low NO_x burners were able to reduce NO_x considerably (over 40 percent) while maintaining combustion efficiency. However, the XCL burner is capable of 60 to 70 percent NO_x reduction from uncontrolled levels, which was not achievable with good combustion efficiency in this unit. In this instance, further improvement would be necessary to achieve uniform fuel delivery to the burners, i.e. gravimetric coal feeders. Gravimetric feeders are the norm for many larger pre-NSPS units and most post-NSPS units, and are needed for reliable/repeatable coal regulation. High performance low NO_x burners can reach their potential only when used in combination with systems which accurately and consistently regulate their air and fuel supply.

MULTI-FUEL XCL BURNER DEVELOPMENT/COMMERCIALIZATION

Late in 1986, B&W was approached by ENEL, the electric utility of Italy, and Ansaldo Componenti (ACO) - B&W's licensee in Italy, concerning low NO_x combustion technology. ENEL was evaluating these technologies world-wide, in preparation for implementation in Italy. Systems with multi-fuel capability (pulverized coal, No. 6 oil, natural gas) were needed for use with the many cell burner-equipped existing units, and also for more conventional wall-fired units. (As an aside, B&W received a contract to supply 15 multi-fuel Low NO_x Cells for one of ENEL's 320 MW units and start-up is scheduled for later this year.) The focus for the conventional wall-fired units was to perform a state-of-art demonstration of low NO_x combustion equipment at the Brindisi Sud Power Station. This new power plant will have four B&W designed/ACO supplied 660 MW, supercritical units. The units had been designed to fire pulverized coal and No. 6 oil using Dual Register Burners/Compartmented Windboxes. Unit 1 was already well along in erection and would retain this system, but NO_x ports were added to further reduce NO_x. Unit 2 was at a stage where the combustion system could be changed but timing was critical.

B&W received the contract to supply 56 multi-fuel XCL burners for Brindisi Sud 2. The combustion system design would also include addition of gas firing capability, dual zone NO_x ports above the top burner row, and retain gas recirculation to the compartmented windboxes. The project was contingent upon demonstrating performance in prototype scale combustion tests firing natural gas, fuel oil, and coal. B&W designed the XCL multi-fuel burner (Figure 4) (patent pending) to retain in-burner fuel staging techniques incorporated for coal firing, and to make use of these principles firing fuel oil and natural gas. All of the fuel elements for coal, oil, and gas firing are enclosed within the flame stabilizing ring in the center of the burner. A small quantity of core air is admitted to the nozzle during gas or oil firing to partially oxidize the fuel and generate hydrocarbon radicals in the core of the flame. These effectively eliminate NO_x in the near flame and go on to mix with and limit NO_x formation in the later stages of combustion (char oxidation). As before, the burner is configured with multi-stage air vanes to control introduction of secondary air to the flame and final mixing. A slide damper controls air flow to the burner and a pitot grid is used to measure air flow.

B&W performed the large scale combustion tests - nominal 120 million Btu/hr - at Riley Research's tunnel facility in Worcester, Massachusetts. The test furnace, shown in Figure 5, is 18 ft. wide, 60 ft. long, and 18 ft. tall not including the hopper bottom. Interior surfaces of the roof, hopper, and sidewalls are insulated for a distance of 40 ft. from the end wall on which the burner is mounted. Combustion tests were performed with the burner end wall uninsulated and insulated to compare thermal effects. Staging ports used in this program were positioned on the sidewalls 16 ft. from the the burner wall. Secondary air, primary air, and NO_x port air were measured and controlled, as were each of the fuels. A system was installed for these tests to supply, meter, and regulate recirculated flue gas (GR) to the secondary air. A B&W CFS gas-fired lighter was used for ignition, and the facility's flame scanners/flame safety system was used for these functions. Gases exiting the furnace were continuously monitored for temperature, O_2, CO, CO_2, and NO_x. The natural gas fired was typically 95 percent methane and 1030 Btu/ft^3. The No. 6 oil fired was selected to match the oil specified for Brindisi Sud, and a typical analysis is shown in Table 2. Fuel nitrogen ranged from 0.30 to 0.41 and averaged 0.37 percent. Two coals were fired during the tests (Table 2). The "low volatile" (LV) bituminous was similar to the design coal and the higher volatile (HV) coal was tested for comparison. The LV coal has a relatively high FC/VM ratio making it less conducive to NO_x control measures, and the HV coal was more typical of bituminous coal used by U.S. utilities.

XCL PERFORMANCE - NATURAL GAS

Combustion testing took place through fall and winter, 1987. Performance firing gas and oil were of primary importance (coal performance was already commercially demonstrated). A total of 215 tests were performed firing natural gas. These began with evaluations of four different gas spud designs, which included two standard designs and two new designs to promote fuel staging effects. Figure 6 shows NO_x test results for B&W's standard variable mix spud and the HEMI spud (patent pending). At high load (100 MKB), without use of GR or staging ports, and 8 percent excess air, the variable mix spud produced 131 ppm NO_x (all ppm figures are referenced to 3% O_2). At the same conditions, the HEMI spud produced 56 ppm NO_x with 34 ppm CO. Secondary air temperature was 600°F. Figure 6 also includes predicted NO_x for a circular burner with VM spuds, based on thermal scaling factors developed in this program and B&W standards. The XCL burner reduced NO_x 32 percent compared to the circular burner, each using the same gas spud design. The XCL plus HEMI spud reduced NO_x 71 percent, relative to the circular/VM spud. XCL results are compared to standard NO_x predictions for another low NO_x burner, the PG-DRB, in Figure 7. The XCL NO_x emissions are much lower than the PG-DRB at low GR rates and emissions performance converges at high levels of GR. Note the PG-DRB is intended for use with GR so the emissions corresponding to low GR rates do not reflect normal operation. However, the XCL achieves low NO_x emissions without use of GR, for situations which require this; and produces lower NO_x for a given level of GR up to very high GR rates.

Extensive characterization tests were performed on the XCL burner with HEMI spuds. The end wall, on which the burner was located, was insulated so that all furnace surfaces for a distance of 40 ft. were insulated. Increasing firing rate to 124 MKB (100% load) with the insulated firing wall resulted in 74 ppm NO_x with 36 ppm CO. Table 3 shows results for various loads with and without NO_x ports and gas recirculation (GR). Full load NO_x emissions were reduced to 50 ppm with moderate quantities of GR, and down to 33 ppm NO_x staged with higher GR. Excellent emission performance was also achieved at reduced loads, e.g. 56 ppm NO_x unstaged/No GR at 32 percent load or 23 ppm NO_x with GR at the same load.

Flame stability and turndown were exceptional, owing to the placement of the fuel elements within the flame stabilizing ring. No furnace rumble was encountered in any of the tests. Stable, well-shaped flames were anchored at the burner from 1.8 MKB (minimum attempted) to 140 MKB (maximum available), representing 78:1 turndown.

XCL PERFORMANCE - NO. 6 OIL

The No. 6 oil combustion tests commenced with evaluation of several Y-Jet and Racer atomizer sprayer plates. The emphasis was on NOx/CO emissions and smoking tendencies at high load without GR or staging ports. The facility was not equipped to measure opacity, but observation ports were sufficient to qualify furnace clarity. The standard Racer plate, with high oil pressure/low atomizing steam consumption produced the best results. The flame shape was controllable and free from smoke over a very wide range of conditions. Characterization tests followed with the Racer and XCL burner. Table 4 summarizes some key results of the 142 tests performed firing No. 6 oil. With the front firing wall insulated and 600°F secondary air, NO_x emissions were 118 ppm with 38 ppm CO at full load, unstaged without GR. NO_x was reduced to 88 ppm by staging with moderate GR. Emission performance was similar at middle loads, but NO_x tended to increase at lower loads as stoichiometry unavoidably increased. Air staging and GR would partly offset this tendency, e.g. at 35 percent load, NO_x was limited to 133 ppm with 48 ppm CO with staging and 17 percent GR.

The XCL burner was reconfigured for a portion of the tests to defeat the NO_x control features and simulate a pre-NSPS circular burner. The flame stabilizing ring and air separation vane were removed, an impeller was installed, and the burner vanes were adjusted to produce a short bushy flame characteristic of circular burners. Note previous lab and field tests had demonstrated the validity of this approach, which provided a cost-effective means of developing baseline results for oil and coal, in order to develop thermal scaling factors. Figure 8 compares performance of the "circular burner" to the XCL burner. The XCL reduced NO_x 42 percent relative to the circular with zero GR, and by 45 percent with 20 percent GR. The standard prediction for the PG-DRB is also shown in Figure 8. XCL NO_x emissions are 28 percent lower without any GR, and 24 percent lower with 20 percent GR.

XCL flame stability was good throughout the tests firing No. 6 oil. Turndown, primarily a factor of atomizer performance, was 10:1.

XCL PERFORMANCE - PULVERIZED COAL

NO_x emissions firing pulverized coal in the multi-fuel XCL in this facility were similar to results achieved previously in lab and field tests. At conditions of full load, unstaged, firing the lower volatile coal, NO_x emissions were typically 250 ppm. At the same conditions, the higher volatile coal resulted in NO_x emissions of 236 ppm. CO emissions were near 100 ppm for either case. Unburned carbon loss, as measured by dust samples collected at the furnace exit, was 1.4 percent in this relatively cool, slow-mix furnace. Use of the NO_x ports did little to impact NO_x, which is attributed to the proximity of the NO_x ports to the burners (4). However, the additional downstream turbulence provided by the NO_x ports served to reduce unburned carbon loss to 0.3 percent.

Scale-up of the results from the gas, oil, and coal tests indicated the XCL would meet or exceed performance expectations. Consequently, B&W manufactured 56 XCL multi-fuel burners for installation at Brindisi Sud 2, scheduled to start up later in 1989

XCL OIL/GAS

The exceptional emission performance of the XCL multi-fuel burner firing natural gas and No. 6 oil led to the decision to commercialize the burner for gas/oil applications. The XCL oil/gas burner (Figure 9) retains the functional design parameters of the multi-fuel design, but obviously without the coal components. The oil atomizer and HEMI gas spuds are enclosed within the flame stabilizing ring. Secondary air is controlled by a sliding damper, measured by a pitot grid, and distributed and swirled by multi-stage air vanes (similar to the S-burner). Provision is made for vane adjustment although the combustion tests identified optimum settings for the vanes in the inner and outer air zones. These settings are the same for firing either natural gas or fuel oil. Vane adjustment, if needed, will be performed during commissioning and then vanes will be locked in position. Subsequent air control would be provided by the sliding air damper. The HEMI spuds are designed to permit adjustment or removal from the burner platform.

The XCL oil/gas can be used in combination with other NO_x control measures such as NO_x ports and GR when conditions dictate. The burner is designed for use in open windboxes for utility and many industrial boiler applications.

XCL-FM

A rather unique industrial boiler type in need of low NO_x combustion equipment is the package boiler. These boilers are completely shop assembled and shipped, usually by rail car, for use in a wide variety of applications. These boilers are characterized by compact furnaces with high volumetric heat release rates, and are designed to operate with little or no supervision. The vast majority of the units use unheated combustion air and fire natural gas, No. 2 oil, or No. 6 oil.

B&W developed the XCL-FM for use with package boilers (FM is B&W's designation for its line of package boilers). The development program centered on an extensive series of combustion tests performed on the FM boiler (Figure 10) at our Alliance Research Center, during the spring and summer of 1988 (5). The tested conditions included use of natural gas, No. 2 oil, and No. 6 oil (with and without N_2 doping) at various loads and stoichiometries, with and without gas recirculation to the windbox. Considerable furnace probing was performed to study temperature, NO_x, CO, CO_2, and O_2 during flame development. Several varieties of HEMI spuds and oil atomizers were tested to optimize performance in this furnace. The XCL-FM burner (Figure 11) was designed for a nominal full load input of 60 MKB using ambient air. The furnace end of the burner can be seen to be similar to the XCL oil/gas design, while the upstream portion of the burner was simplified. The sliding air damper and pitot grid would be superfluous for these single burner applications.

Some key test results are summarized in Figure 12. NO_x emissions firing natural gas were very close to results achieved in XCL multi-fuel program. Full load NO_x emissions were 60 to 70 ppm without GR, and 30 ppm with 17 percent GR (maximum available GR at full load). At 2/3 load, NO_x could be reduced to 19 ppm with 20 percent GR. CO was less than 50 ppm. Emission results with No. 2 oil were similar to natural gas, with NO_x in the low 60's ppm without GR. But GR had less influence on NO_x, e.g. 45 ppm NO_x with 17 percent GR. The No. 6 oil tested had 0.2 percent fuel nitrogen inherently, and pyridine was used in selected tests to raise fuel nitrogen to evaluate the influence on NO_x. Figure 12 shows the influence to be significant and non-linear. As expected, NO_x emissions were much higher with No. 6 oil and some adjustments were necessary to prevent flame impingement and deposition. While these adjustments were successful in this regard, they increased NO_x, e.g. originally NO_x was typically 155 ppm and increased to 200 ppm after adjustments (without GR or staging).

A commercial demonstration of the XCL-FM is underway on one of the boilers at the California Institute of Technology in Pasadena. Burner tuning and performance tests will take place this spring.

SUMMARY

Babcock & Wilcox has developed a new generation of burners which effectively make use of fuel staging principles to limit NO_x emissions to very low levels. The XCL burners benefit from this advanced technology plus B&W's experience in NO_x control over a wide range of applications. The mechanical design is derived from the S-type burner which has demonstrated reliability and performance improvements in numerous coal-fired utility boilers. The various XCL burners are designed to facilitate use in new or retrofit applications, ranging from multi-fuel (coal, oil, gas) supercritical steam generators to package boilers. Some applications are in commercial operation while others are scheduled for demonstration this year.

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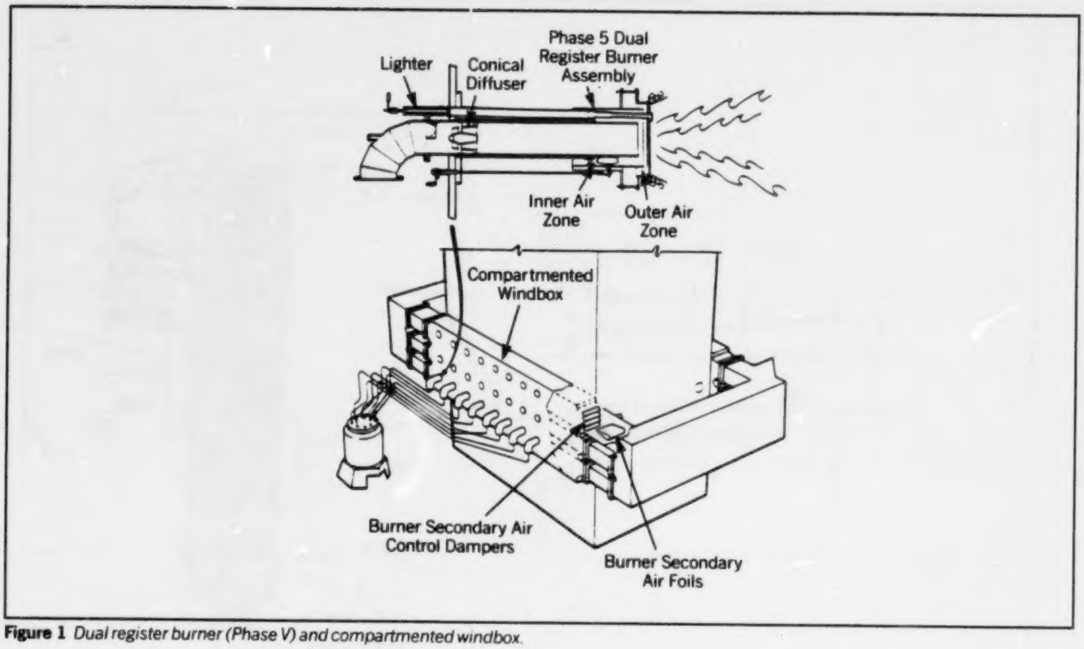
Phase 5 Dual Register Burner Assembly
Lighter
Conical Diffuser
Inner Air Zone
Outer Air Zone
Compartmented Windbox
Burner Secondary Air Control Dampers
Burner Secondary Air Foils

Figure 1 *Dual register burner (Phase V) and compartmented windbox.*

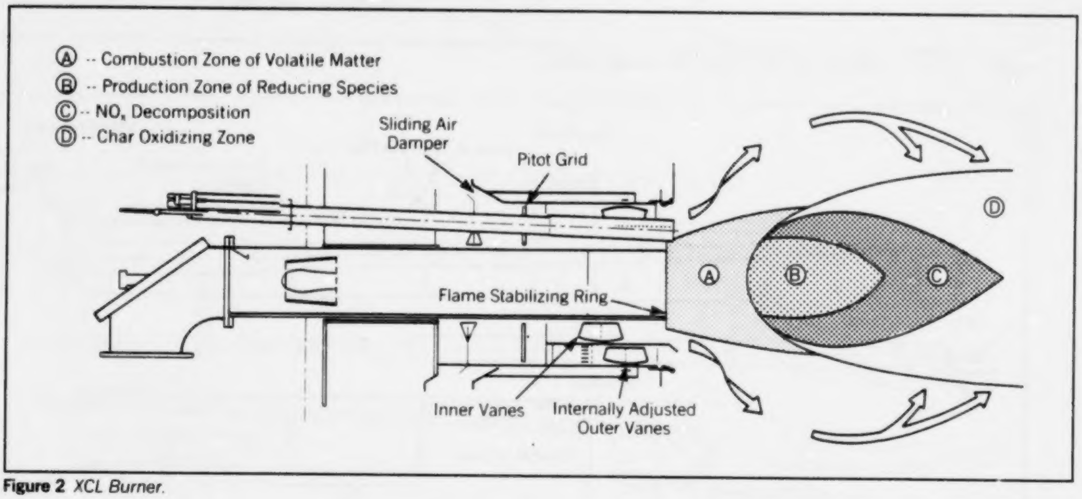
Ⓐ -- Combustion Zone of Volatile Matter
Ⓑ -- Production Zone of Reducing Species
Ⓒ -- NOx Decomposition
Ⓓ -- Char Oxidizing Zone
Sliding Air Damper
Pitot Grid
Flame Stabilizing Ring
Inner Vanes
Internally Adjusted Outer Vanes
A
B
C
D

Figure 2 *XCL Burner.*

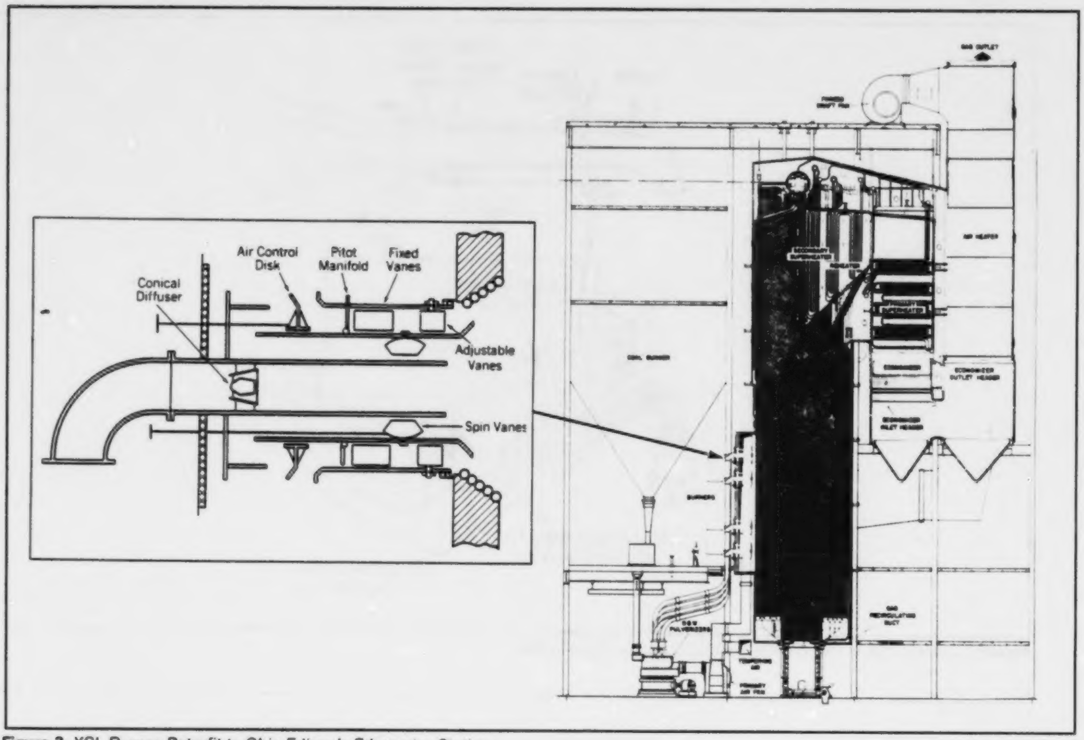
Air Control Disk
Pitot Manifold
Fixed Vanes
Conical Diffuser
Adjustable Vanes
Spin Vanes

Figure 3 *XCL Burner Retrofit to Ohio Edison's Edgewater Station.*

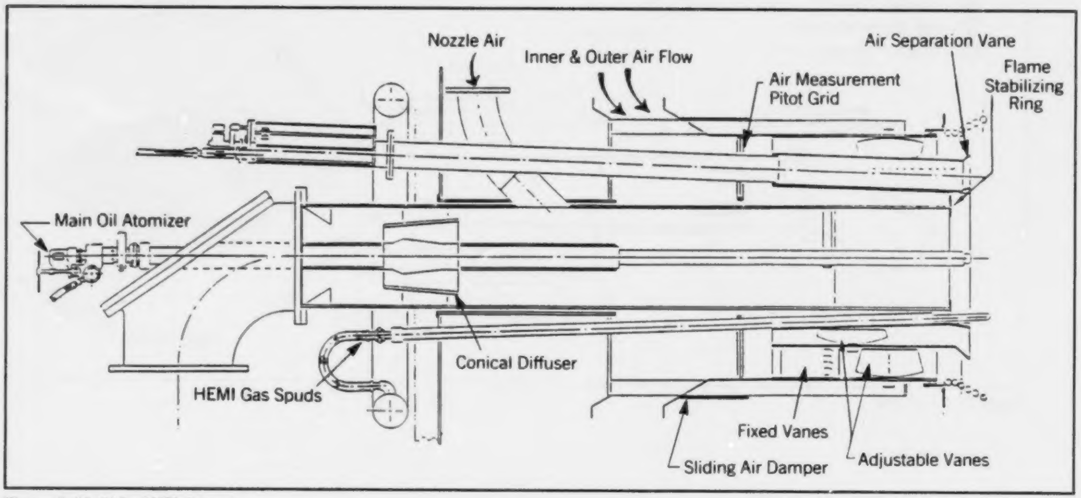
Nozzle Air
Inner & Outer Air Flow
Air Separation Vane
Flame Stabilizing Ring
Air Measurement Pitot Grid
Main Oil Atomizer
Conical Diffuser
HEMI Gas Spuds
Fixed Vanes
Adjustable Vanes
Sliding Air Damper

Figure 4 *Multi-fuel XCL burner.*

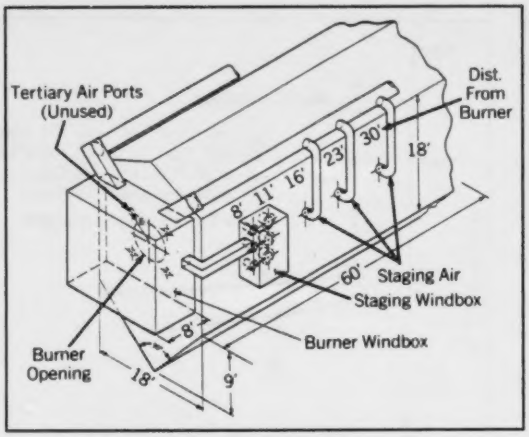
Tertiary Air Ports
(Unused)
Dist.
From
Burner
30'
18'
23'
16'
11'
8'
60'
Staging Air
Staging Windbox
8'
Burner Windbox
Burner
Opening
18'
9'

Figure 5 *Riley test facility.*

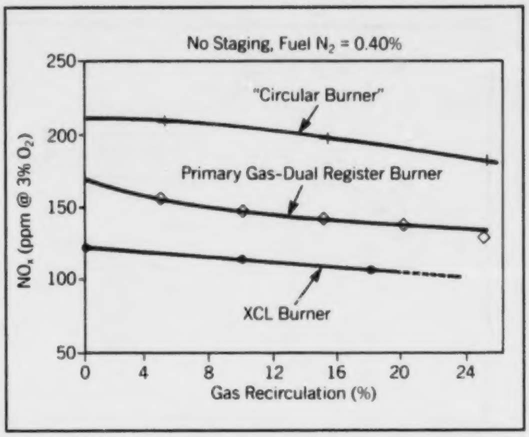

Figure 8 *NO$_x$ Emissions Firing 6 Oil.*

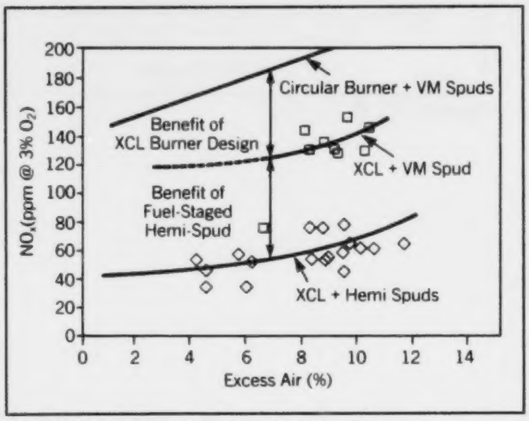

Figure 6 *XCL Burner - Natural Gas Test Results*
No Gas Recirc., No Two-Stage Combustion

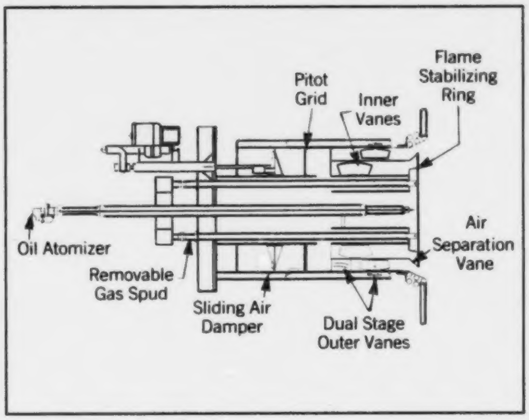
Pitot
Grid
Inner
Vanes
Flame
Stabilizing
Ring
Air
Separation
Vane
Oil Atomizer
Removable
Gas Spud
Sliding Air
Damper
Dual Stage
Outer Vanes

Figure 9 *XCL Oil/Gas Burner.*

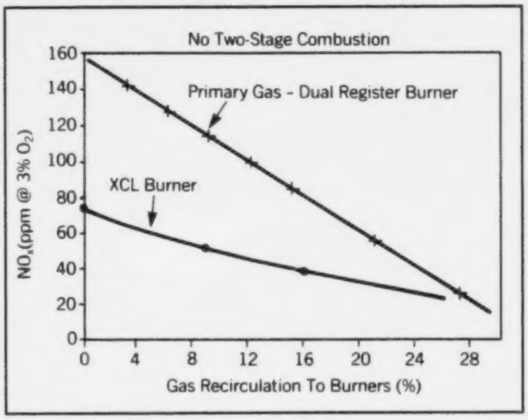

Figure 7 *NO$_x$ Emissions Firing Natural Gas.*

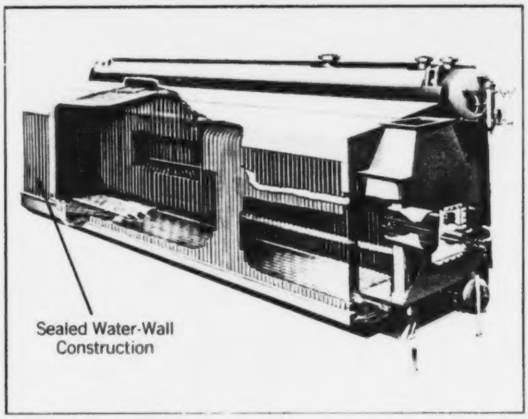
Sealed Water-Wall
Construction

Figure 10 *FM Boiler.*

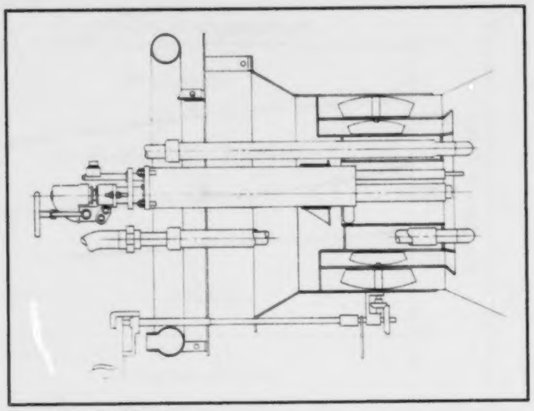

Figure 11 *XCL FM burner.*

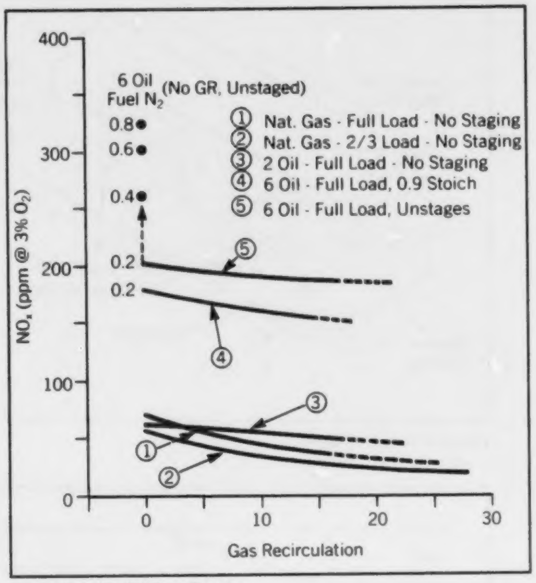

Figure 12 *XCL FM Test Results.*

Table 1
LIMB Retrofit Results*

	Circular Burners	XCL Burners-with Impellers	XCL Burners-Tuned
NO_x (lb/10^6 Btu)	0.89	0.53	0.47
CO(ppm @ 3% O_2)	20	115	60
Carbon in Flyash	2.2	2.8	6

* - Full load, normal/excess air

Table 2
Prototype Test Fuel Analyses

Fuel	#6 Oil	"Low Volatile" Coal	High Volatile Coal
Proximate (%)			
Moisture		4.3	8.3
Volatile Matter		23.0	29.10
Ash		13.5	10.90
Fixed Carbon		59.2	51.70
FC/VM Ratio		2.6	1.8
HHV (Btu/lb)	18356	12642	12141
Ultimate (%)			
Moisture	-	4.3	8.3
Carbon	86.44	71.0	67.9
Hydrogen	10.71	4.4	4.4
Nitrogen	0.37	1.0	1.5
Oxygen	0.25	3.0	5.4
Sulfur	2.16	2.8	1.6
Ash	0.07	13.5	10.9
Specific Gravity	0.94		
API Gravity	12.3		
Conradson Carbon	12.1		
Asphaltenes	4.4		

Table 3
XCL Burner - Natural Gas Test Results

Load %	NO_x (ppm @ 3% O_2)	CO	Burner Stoich.	Gas Recirc. %	Excess Air %
100	74	36	1.07	0	7
100	65	46	0.89	0	7
100	50	35	1.07	9	7
100	33	36	0.81	16	8
50	45	35	1.12	0	12
50	29	37	0.85	18	13
32	56	62	1.35	0	35
32	23	39	1.21	20	21

Table 4
XCL Burner - #6 Oil Test Results

Load %	NO_x (ppm @ 3% O_2)	CO	Burner Stoich.	Gas Recirc. %	Excess Air %
100	118	38	1.08	0	8
100	95	45	0.90	0	8
100	88	46	0.88	10	7
62	123	36	1.16	0	16
62	83	36	0.80	18	17
35	133	48	0.96	17	37

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APPLICATION OF LOW NOx COMBUSTION TECHNOLOGIES TO A LOW VOLATILE COAL FIRING BOILER

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ABSTRACT

Low NOx combustion technologies are introduced on low volatile coal firing with relation to the application of a INPACT method, developed for low NOx firing which was proved effective for the reduction of NOx emission on boilers fired steaming coal(1,2). We fundamentally studied the characteristics of NOx emission for low volatile coals using a reactor tube and/or a tunnel type test furnace, and these studies were reflected to design of a 530 t/h boiler fired steaming coal with blending anthracite or petroleum coke. The field test results showed INPACT method also contributed both reductions of NOx emission and of unburned loss on low volatile coal firing by multi-air staging through IAP (Interstage Air Ports) and OAP (Over-fire Air Ports).

INTRODUCTION

Recently, in Japan, utility boilers and industrial boilers have been become to use various kinds of coal from foreign countries for the purpose of diversifying fuel supply source and for political reasons. Especially, industrial users intend to use anthracite or petroleum cokes for saving fuel cost, by blending of a steaming coal so as to improve the properties of low volatile coals having less flame stability, less char oxidation rate and less NOx reduction than higher volatile coals. For low NOx combustion technologies, IHI already developed INPACT (IHI NOx Preventing Advanced Combustion Technologies) method, of which firing concepts are illustrated in Figure 1 in comparison with other low NOx combustion methods, and demonstrated remarkable NOx reduction of less than 100 ppm for a 600 MWe coal firing boiler (1). However, blending low volatile coal was roughly estimated lowering both of NOx reduction and of combustion efficiency, and then fundamental studies were conducted to reflect to design of a 530 t/h boiler newly installed.

For the evaluations of NOx reduction on low volatile coal firing, we tested various kinds of coal ranged from 9% to 42% as volatile content in coal using a reactor tube and/or a tunnel type test furnace. On the fundamental test by the reactor tube, we investigated both characteristics of coal-N release and of coal-N

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conversion to NOx, independently, for five (5) different coals. And then, we attempted to demonstrate the differences of NOx emission and of the degree of NOx reduction in fuel rich condition, using the test furnace for four (4) different coals and three (3) blended coals of high and low volatile coals. For latter study, we also investigated the influence of coal blending on flame stability in horizontal firing system conventionally used, by quantitative measurements of spectra emitted from pulverized coal flame.

Accordingly, we decided an optimum blend ratio of low volatile coal such as anthracite or petroleum coke taking into consideration of NOx emission and unburned loss. For minimizing unburned loss, a rotary type classifier was adopted to be mounted in a roller type IHI-FW pulverizer so as to improve coal fineness. Firing tests were conducted for 30% of blended coals of anthracite and of petroleum coke, respectively, and it was demonstrated INPACT method fully available for NOx reduction on low volatile coal firing, from the operational results of 140 ppm of NOx emission. Especially, although the reduction of NOx emission was always recognized to cause the increment of unburned loss, adopting INPACT method was remarkably resulted to realize both reductions of NOx emission and of unburned loss.

GENERAL CHARACTERISTICS OF LOW VOLATILE COALS

Generally speaking, in designing a horizontal-firing boiler fired low volatile coal, it is important to estimate the characteristics of flame stability, of char oxidation and of NOx emission. We studied such characteristics using a reactor tube and/or a small size tunnel type test furnace. The fundamental studies were conducted to clarify the following items.

(1) the degree of NOx reduction and NOx emission for the variation of volatile content in coal

(2) an allowable blend ratio of low volatile coal and its governing factors, for blended coal of low volatile coal and of steaming coal

(3) the effect of unburned loss on NOx emission under low NOx combustion

NOx formation on coal firing is well-known to be divided into two phases, that is; volatile-NOx formed in early combustion stage and char-NOx in post flame. Firing low volatile coal was roughly estimated to have a property of less NOx reduction than steaming coals on staged firing as low NOx combustion, due to less volatile-NOx, which could be easily decomposed into molecular nitrogen in early combustion stage under fuel rich condition, and higher char-NOx, which had a difficulty of NOx control by low NOx firing. Therefore, we firstly investigated the effect of volatile content on coal-N conversion to NOx in fuel rich condition by the reactor tube. And then, we conducted firing test so as to demonstrate the difference of NOx reduction for the variation of volatile content in coal. In the latter study, we also estimated the influences of blending low volatile coal on flame stability and on unburned loss.

Test Facility

Reactor Tube. The characteristics of coal-N conversion were experimentally studied in the down flow type electrically heated reactor tube (ø47 mm in diameter, 1.2m in length). Pulverized coal particles (70 - 80% pass through a 200 mesh sieve) were dried and fed in nitrogen stream into the reactor, controlled at constant wall temperature. Oxygen was diluted with nitrogen and was fed into the top of the reactor. For simulating staged firing oxygen also fed through alumina probe inserted from the bottom of the reactor. Product gas and unreacted char was sampled though a water-cooled sample probe from the bottom of the reactor.

Nitrogeneous species such as NOx, NH_3 and HCN were analyzed by a chemiluminescent type monitor (HORIBA ENDA-C211) and FTD type gas chromatograph (SHIMADZU GC-7A) with Porapak Q and Chromsorb 103 as column agents, respectively. Residual char-N and ash content in unreacted char were also analyzed by an oxygen-circulating combustion type analyzer (SUMIGRAPH HC-80). Five (5) different coals were examined and their properties are listed in Table 1.

Test Furnace. Demonstrating combustion performances on low volatile coal firing, we conducted firing test using the tunnel type test furnace. Single burner was installed at the front end of the furnace and observation ports were distributed along with the furnace. OAP ports were also located in a circle to realize stage firing. Specification of the test furnace is as follows:

Type ; Horizontal, cylindrical and non-pressurized water jacket cooling
Capacity ; 200 kg/h of pulverized coal (equivalent to 1.8 MWt)
Dimension ; 1.3m in inside diameter, 7m in length

Figure 2 shows the general arrangement of the test furnace. The furnace was divided into two parts by division bricks, they are; combustion chamber and heat recovery area. Fire proof bricks and castable refractory were installed inside of the furnace so as to simulate flame temperature of an actual furnace. We tested four (4) different coals, of which properties are also listed in Table 1, included anthracite as low volatile coal, and three (3) different blended coals of anthracite.

Estimating flame stability, an attempt was made to quantitatively measure the intensity of spectra emitted from coal flame near the ignition field, by means of a monochromator as spectroscopic analysis. For only checking flame failure, flame detector can be applicable, however, an analogical output of a conventional flame detector having tendency indicated saturation value makes no comparison for our purposes. The system comprises an optical probe, an optical fiber as a transmitter and a monochromator with a signal analyzer. The optical probe was set on burner face parallel to burner axis to view the ignition field. We mainly directed our attention to spectra covering visible band due to minimize the transmission loss of the intensity through the optical fiber, though pure quarts fiber of large size was adopted.

Results and Discussions

Characteristics of Coal-N Conversion to NOx. Fundamentally evaluating NOx emission for low volatile coal, we firstly investigate the effect of volatile content on the activities of volatile-N release in pyrolysis process and in char oxidation process, and then estimated the characteristics of coal-N conversion to NOx in fuel rich condition, using the reactor tube.
Figure 3 shows both of volatile-N release, $\eta_{P.N}$, and of volatile yield, η_P, plotted against volatile content, at 1673°K of coal pyrolysis temperature. Accordingly, the following empirical relations were obtained.

$$\eta_P = Q\ VMp = 1.4\ VMp \quad \text{at } 1673^\circ K \qquad (1)$$

$$\eta_{P.N} = \eta_P^{0.629} = 1.24\ (VMp)^{0.629} \quad \text{at } 1673^\circ K \qquad (2)$$

where, Q and VMp denote the volatile enhancement factor, proposed by Mitchell and Tarbel (3), and proximate volatile content as dry basis, respectively. Higher

volatile coal caused more release of volatile-N in the relation to volatile content, as was expected.
Figure 4 shows the effect of coal pyrolysis temperature on the volatile enhancement factor as volatile yield and on volatile-N release, for coal E. As the results, the following empirical relations were also obtained.

$$Q = 3.4 \exp(-2,870/RT) \quad (3)$$

$$\ln (1 - \eta_p) = \ln (Np/No) = -34.6 \exp (-12,000/RT) \quad (4)$$

where, Np, No, R and T represent residual char-N, coal-N in raw coal, gas constant and reactor temperature, respectively. As reported earlier researchers (3,4), with the increment of temperature more volatile-N was released. Then, we also investigated the activities of char-N release in char oxidation process. Char conversion and char-N release were counted by both data of volatile yield/volatile-N release in pyrolysis test and of coal conversion/coal-N release in oxidation test. Figure 5 shows the relation between char conversion, η_{char}, and char-N release, $\eta_{char.N}$. In the figure, the results of the char oxidation tests for coal B and coal E are also plotted. Consequently, following correlations were experimentally obtained.

$$\eta_{char.N} = 0.875\, \eta_{char} + 0.05 \qquad \text{at } \eta_{char} < 0.4 \quad (5)$$

$$\eta_{char.N} = \eta_{char} \qquad \text{at } \eta_{char} > 0.4 \quad (6)$$

Eq. (5) possibly indicated that retained tar-N was released prior to char-N release. If char retained volatile content, retained volatile-N was also released prior to char-N release, according to the plotted data of char oxidation test for coal B, of which char was roughly adjusted to retain 11.6% of ultimate volatile yield. As the results, it was clarified char-N release approximately coincided with char conversion.

Next, estimating the differences of NOx reduction for the variation of volatile content, we investigated the characteristics of coal-N conversion to TFN (Total Fixed Nitrogen), defined as the sum of NOx, NH_3 and HCN, in fuel rich condition with 1.1 second of residence time. We attempted to make relations between coal-N conversion to TFN, CR_{TFN}, and the ratio of coal conversion to ultimate volatile yield, η/η_p, in first stage combustion. For all coals tested, as plotted in Figure 6, coal-N conversion to TFN could be minimized at the condition of 1.15 of η/η_p, becoming less than 5%. Firing low volatile coal in a boiler, consequently, we could estimate NOx emission becoming higher than the case of steaming coals, at the condition of same coal conversion in fuel rich region, due to higher value of η/η_p.

Coal-N conversion to TFN included both TFNs originating from volatile-N and from char-N. Therefore, an attempt was made to estimate the contributions of conversion to TFN from both of them, independently. Char-N conversion to TFN was counted from the char oxidation tests, and the results were also expressed against the parameter of η/η_p in Figure 6. Accordingly, in fuel rich condition, higher TFN conversion in low volatile coal oxidation was evaluated to be mainly originated by char-N, converted to NOx in post flame. This estimation may be consistent with the results reported by Phong-anant et al (5) and by Chen et al (6).

Evaluation of NOx Emission. Both demonstrating NOx emission for low volatile coal and estimating NOx level for blended coals of low volatile coal with steaming coal, we carried out firing tests, using four (4) different coals and three (3) different blended coals at the tunnel type test furnace. Semi-anthracite, as a low volatile coal, was selected to attempt to burn independently, and was blended with a steaming coal, coal F listed in Table 1. Blend ratio of semi-anthracite was decided to be ranged from 35% to 75%, taking into consideration of the variation of volatile content in test coals, and their properties were listed below.

		Blend A	Blend B	Blend C
blend ratio	(%)	35	55	75
volatile matter	(%)	18.1	15.3	12.6
fixed carbon	(%)	64.5	68.4	72.3
ash	(%)	14.8	13.4	12.0
moisture	(%)	2.6	2.9	3.1
coal-N as d.a.f	(%)	1.7	1.8	1.9

Figure 7 represents the relation between NOx emission and volatile content with a parameter of staging air ratio. Firing low volatile coal showed the results becoming lower NOx emission without staging combustion, and this was interpreted NOx emission governed by volatile-NOx in air rich condition. Reducing air stoichiometry by staged firing, however, low volatile coal was resulted to have the property of less NOx reduction in comparison with the case of high volatile coal. That is, NOx reduction was counted as follows;

	w/o staging (ppm)	w/30% staging (ppm)	NOx reduction (%)
coal E (31%)	630	150	76
coal F (23%)	600	190	68
coal G (20%)	480	210	56
coal H (9%)	550	350	36
blend A (18%)	600	200	67
blend B (15%)	590	250	57
blend C (13%)	500	260	48

Note: The values in parenthesis above show volatile content in coal.

Accordingly, low volatile coal was resulted to have higher NOx emission in fuel rich combustion. And, this was recognized to be in good agreement with the results of preliminary studies mentioned before.

Figure 8(a) shows an alternative expression for the effect of coal blending on NOx emission, and blending high volatile coal with low volatile coal, NOx emission could be reduced with almost linear relation to blend ratio, as was expected.

Moreover, for the purpose of checking a possibility of NOx reduction for low volatile coal, we also estimated the effect of INPACT method on NOx emission, using a low volatile coal of 18% content. Consequently, further 25% of NOx reduction could be obtained by INPACT method, while INPACT method gave 35% of NOx reduction in steaming coals such as coal E, as was already reported in other papers (1,2). The difference of the effect of volatile content on NOx reduction was estimated due to that of char-NOx formed in post flame.

Evaluation of Unburned Loss. For blended coal of low volatile coal, low NOx combustion was estimated to accelerate the increment of unburned loss, due to less char oxidation rate of low volatile coal (7). The evaluations of unburned loss were also done with those of NOx emission in firing tests. Figure 9 represents the relations between NOx emission and unburned loss for blended coals with their mother coals. In this tests, we adjusted coal fineness to 75 - 80% pass through a 200 mesh sieve for all coals tested. Blending low volatile coal gave the increment of unburned loss, of which values were estimated with a linear relation to blend ratio, as shown in Figure 8 (b).

Evaluation of Flame Stability. We also estimated flame stability for coals blended semi-anthracite. Firstly, we compared a profile of flame spectra in visible wavelength band, and then obtained a relation between the intensity of 600 nm spectrum, as a typical spectrum, and a non-dimensional parameter, x/D (x; ignition distance, D; burner throat diameter), of ignition delay. Ignition distance was roughly measured by eye through observation ports, the results are plotted in Figure 10 (a). The ignition delay caused to weaken the intensity of the spectrum detected parallel to burner axis, due to light scattering through unreacted pulverized coal dust. In the tests, coal H and Blend C were resulted to have a big ignition delay even though the air swirl was adjusted, and remarkable reduction of the intensity was detected. Consequently, it was interpreted that the spectrum intensity was available for estimating ignition delay, which was in close relation to flame stability. Figure 10 (b) shows an alternative expression of a relation between the spectrum intensity and volatile content in coal tested. Volatile content in coal gave a significant effect on flame stability, and allowable volatile content was roughly estimated to around 15% in horizontal firing system conventionally used.

Flame stability was also affected by operational parameters such as the flow ratio of primary air to coal at coal nozzle, air velocity through burner throat, air temperature, swirl intensity and so on. Taking into consideration of strict limitation of NOx emission in Japan, we only investigated the effect of staged firing, which was in a relation to the second parameter mentioned above, on flame stability. Reducing air flow through a burner showed to improve spectrum intensity for low volatile coals, whereas high volatile coals gave no deviations of the intensity by air staging, as was represented in Figure 11. Accordingly, reducing air velocity through a burner was experimentally recognized to give better effect on flame stability.

APPLICATION RESULTS ON A 530 T/H BOILER

Designing of a 530 t/h boiler fired steaming coal with low volatile coal, the results of fundamental studies were reflected as follows;

(1) adopting INPACT method to realize NOx emission less than 180 ppm for both blended coals of anthracite and of petroleum coke

(2) adopting a rotary type classifier mounted on a roller type IHI-FW pulverizer for minimizing the increment of unburned loss by the improvement of coal finess

(3) adopting BUF (Boost Up Fan) for staging air and adopting the mechanism adjusting air velocity through OAP ports for better mixing of staging air and of unreacted char in complete combustion region of furnace

With regard to blending low volatile coal, we made a decision of an allowable blend ratio being around 30%, taking into consideration of NOx emission and of the degree of unburned loss. Figure 12 shows the general arrangement of a 530 t/h boiler, of which specification is typically listed below.

Type	; IHI-FW natural circulation type
Evaporation	; 530 t/h (147.2 kg/s)
Steam cond.	; 131 kg/cm^{2}G (12.85 MPa) x 541°C at superheater outlet 29.7 kg/cm^{2}G (2.91 MPa) x 541°C at reheater outlet

Draft system ; balanced system
Fuel ; steaming coal and blended coal with 30% of anthracite or of petroleum coke
Pulverizer ; 4 sets of IHI-FW MBF pulverizer
Burner ; type IHI DF (Dual Flow) type burner
16 burners (4 raws x 2 stages, opposed arrangement)
Air ports for staging ; OAP (in each front and rear wall)
SAP (in each front and rear wall)
IAP (in each front and rear wall)

Note SAP; Side-overfire Air Port, IAP; Interstage Air Port

Typical Feature of the Boiler

Adopting INPACT method, staging air through OAP and SAP ports was branched from air duct connected to air preheater outlet and was boosted up by a BUF, of which rotation frequency was controlled in relation to flow rate by a hydraulic coupling connected to a fan for saving of running cost. SAP ports were located at both front and rear walls between OAP port and each corner, for the purpose of promoting char oxidation rate in the area near furnace side wall. IAP ports, as typical ports of staging air in INPACT method, were also located at the elevation between top raw of burner and OAP ports so as to realize multi-air staging, which was resulted to be effective for both reduction of NOx emission and of unburned loss. Staging air through IAP was branched from common air duct of burner windbox and was controlled by dampers. The locations of OAP, SAP and IAP ports were decided in consideration of residence time in firing region. Each staging port had a damper at inlet for adjusting the distribution of staging air over furnace width.

Burner spacing, as a factor of burner arrangement, was also designed taking into consideration of liberation rate in firing region, according to the fact that elevating liberation rate gave elevating flame temperature and was resulted to release more volatile-N and to reduce unreacted char in firing region, as was interpreted in Figure 4. For adjusting air stoichiometry to opitimum condition for each burner, IHI has been adopting separate-windbox system, in which air flow was separately fed into each burner from common air duct. Boundary air system was also adopted in the boiler to make oxidizing condition near furnace walls, by introducing fresh air through furnace bottom and through both side walls near furnace hopper.

We adopted a motor-driven rotary type classifier mounted on a pulverizer instead of a conventional (adjustable vane) type classifier. A rotary type classifier with rigid vane has been originally developed for the requirement of producing finer materials on a cement plant, and their experiences were reflected to apply for coals. Coal fineness was adjusted by rotation frequency of motor with VVVF (Variable Voltage and Variable Frequency) control, and a typical result was plotted in Figure 13.

Results and Discussions

We carried out firing tests for a typical steaming coal and for two blended coals of anthracite or of petroleum coke. Coal properties are listed in Table 2. Anthracite and petroleum coke had 11% and 13% of volatile content, respectively, and this anthracite was strictly classified to semi-anthracite in ASTM coal rank. Coal blending was done in the coal conveyance system with running weighers. Prior to performance tests for NOx reduction, we carried out combustion adjustment in consideration of air distribution through each burner and staging air port.

Figure 14 shows the data of NOx emission against BUF rotation as an operational parameter of staging air flow, for a steaming coal and for a blended coal of anthracite. In this case, IAP air was adjusted to minimum flow. With the increment of staging air, NOx emission for coals tested was reduced with a almost linear relation to BUF rotation, and low volatile coal gave higher NOx emission in comparison with the case of a steaming coal. The difference of NOx emission between a steaming coal and a blend coal was 20 - 40 ppm, and was in good agreement with expected value in accordance with the data of firing tests at the tunnel type test furnace.

Next, we investigated the effect of multi-air staging through IAP ports on NOx emission for the purpose of further NOx reduction on blended coal firing. Figure 15 shows the results plotted against damper opening of IAP ports. Increasing IAP air was resulted to further NOx reduction, as similar as the results of another boiler (1). NOx emission for blended coal was resulted to be around 140 ppm and this showed INPACT method was also effective for NOx reduction on low volatile coal firing.

We also checked unburned loss in a series of the firing tests. For a steaming coal, unburned loss was only 0.2 - 0.4% even in low NOx condition. For blended coal of low volatile coal, unburned loss was resulted to become higher. Since unburned loss had a close relation to NOx emission, we evaluated unburned loss against NOx emission as plotted in Figure 16. The differences of unburned loss for both cases with or without multi-air staging adopted in INPACT method were also expressed in the figure. The degree of IAP air flow rate was represented by that of damper opening for IAP ports, and we noted that strengthening of multi-air staging could reduce unburned loss for both blended coals. Consequently, these results showed INPACT method to give better effect for improving combustion efficiency under the condition of low NOx firing.

Plant users intend to take special care how reducing condition gives furnace corrosion in INPACT method or even in conventional staged firing. Generally speaking, furnace corrosion has a close relation to sulphur content in coal used. According to our experiences, a high sulphur domestic coal of more than 3% caused corrosion troubles both for a low NOx firing boiler and for a conventional firing boiler, however, controlling sulphur content less than 2% by coal blending was resulted to reduce corrosion troubles remarkably. Fortunately, most of imported coals are low sulphur coals in Japan, and for the boiler applied INPACT method we also confirmed that no corrosion phenomena was observed on tube surface in water wall after one (1) year continuous operation.

CONCLUSION

We clarified both characteristics of NOx emission and of unburned loss for low volatile coal and then applied INPACT method to a low volatile coal firing boiler. Following evaluations were summarized from the results in the fundamental tests and in the field tests of a 530 t/h boiler newly installed.

(1) INPACT method was also fully effective for NOx reduction and for minimizing the increment of unburned loss on low volatile coal firing.

(2) We clarified the relation between NOx emission and volatile content in coal included low volatile coal. Consequently, low volatile coal has the properties of higher NOx emission in comparison with other steaming coals due to higher char-NOx emission which have a difficulty of NOx control.

ACKNOWLEDGEMENTS

We would like to express our gratitude to our customer for applying INPACT method to a boiler newly installed.

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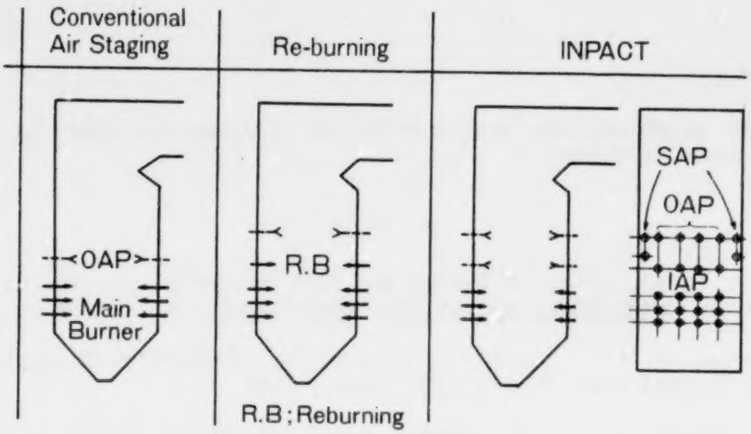

Conventional Air Staging
Re-burning
INPACT
OAP
Main Burner
R.B
R.B ; Reburning
SAP
OAP
IAP

Figure 1. Comparison of Low NOx Firing

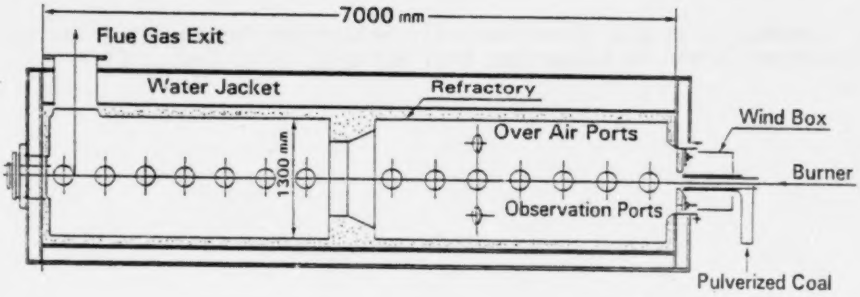

7000 mm
Flue Gas Exit
Water Jacket
Refractory
Over Air Ports
Wind Box
Burner
1300 mm
Observation Ports
Pulverized Coal

Figure 2. General Arangement of Tunnel Type Test Furnace

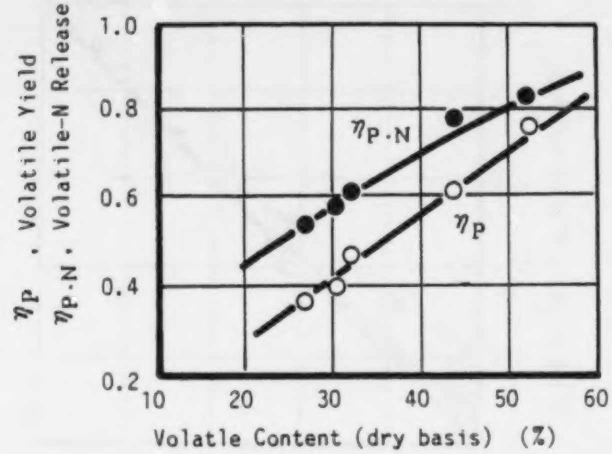


Figure 3. Relation between Volatile Content in Coal and Both of Volatile Yield and of Volatile-N Release

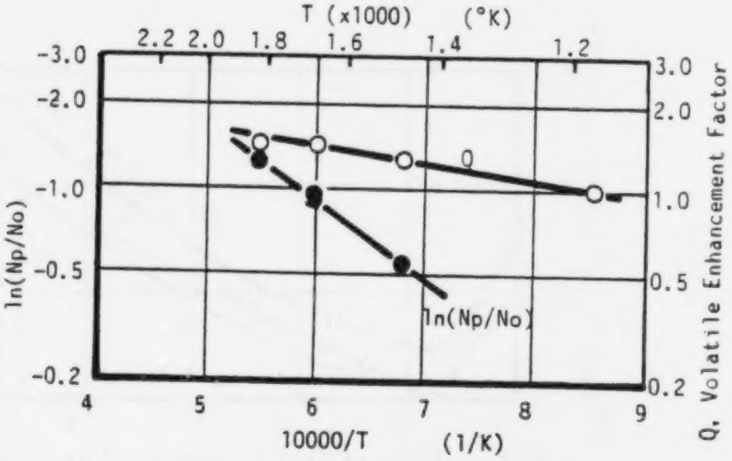


Figure 4. Effect of Coal Pyrolysis Temperature on Volatile-N Release and on Volatile Yield

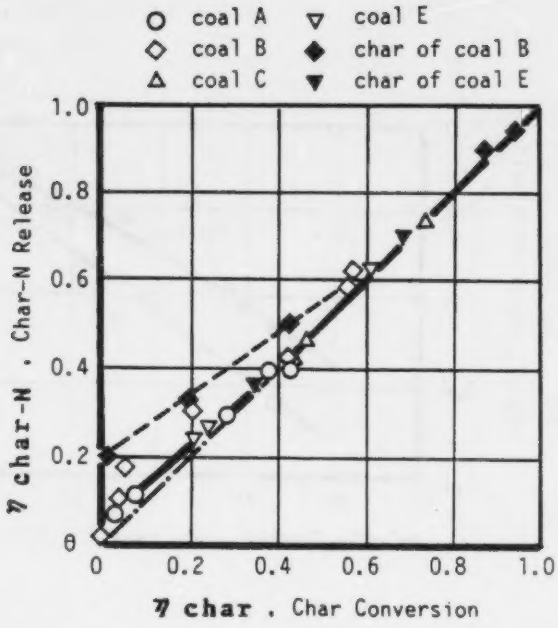


Figure 5. Relation between Char Conversion and Char-N Release

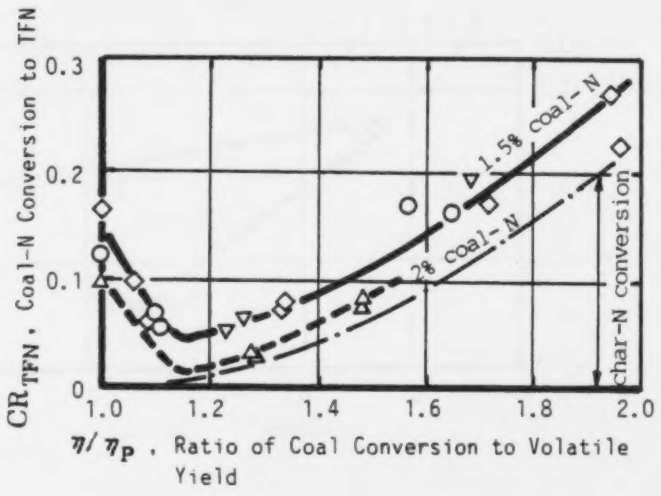


Figure 6. Relation between Coal-N Conversion to TFN and Ratio of Coal Conversion to Volatile Yield

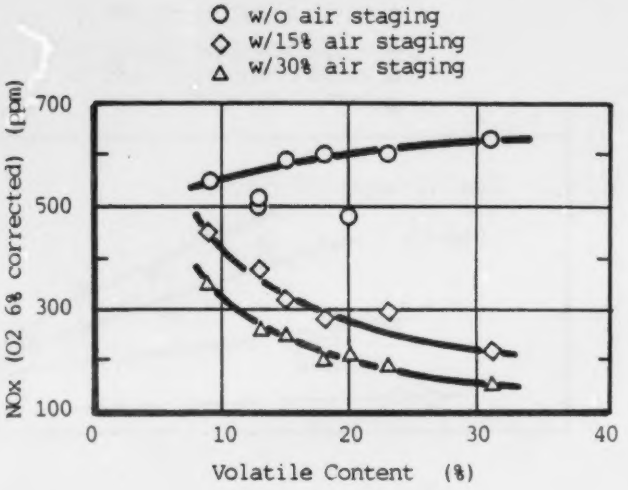
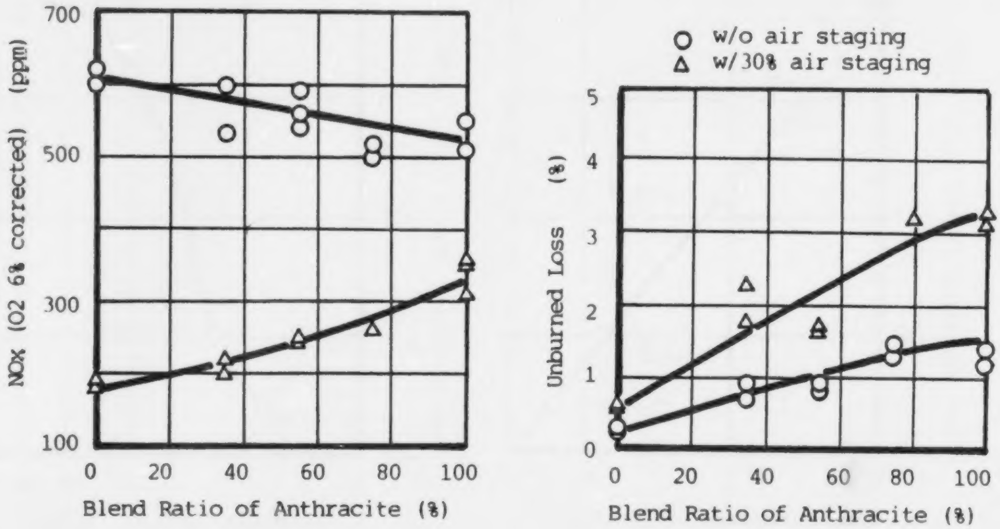


Figure 7. Relation between NOx Emission and Volatile Content in Coal



(a) NOx Emission

(b) Unburned Loss

Figure 8. Effect of Coal Blending on NOx Emission and Unburned Loss

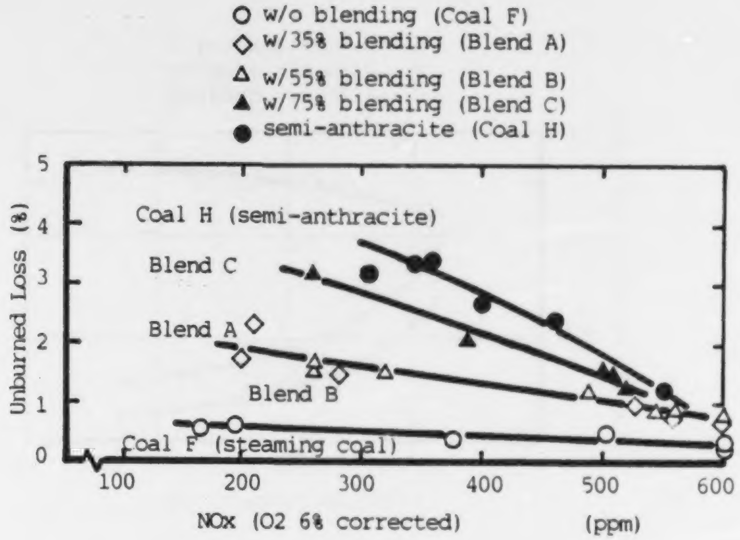
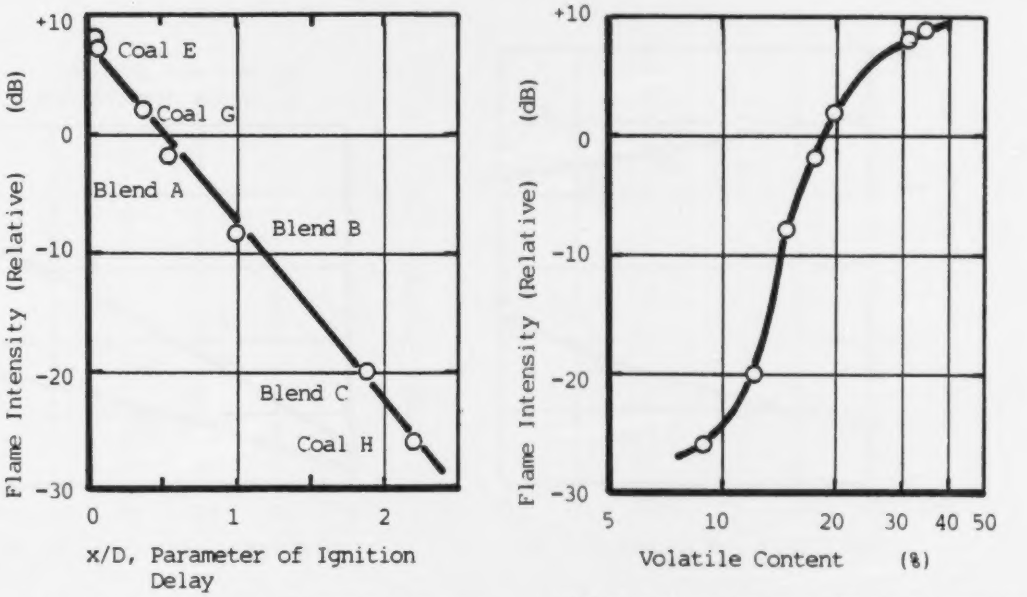


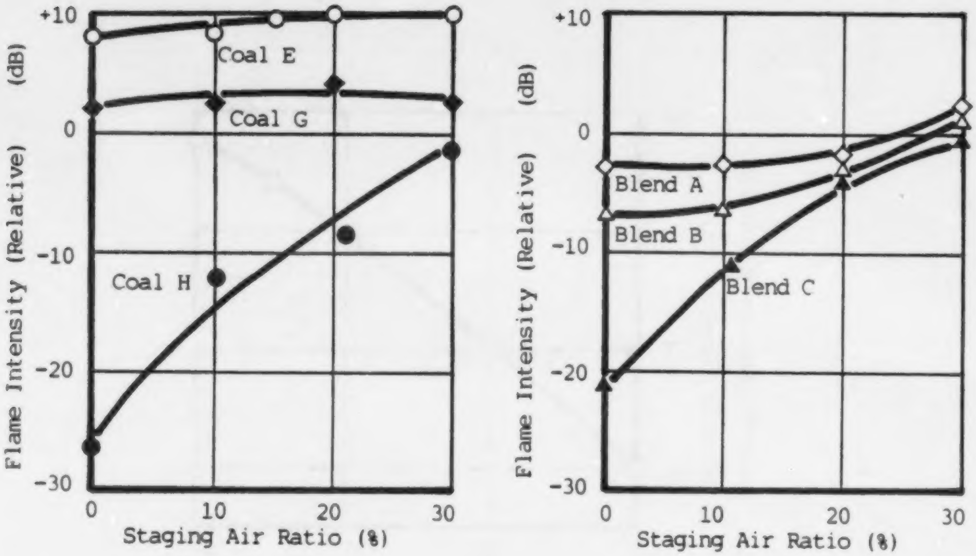
Figure 9. Relation between NOx Emission and Unburned Loss for Blended Coal of Low Volatile Coal



(a) Relation between Flame Intensity and Ignition Delay

(b) Relation between Flame Intensity and Volatile Content in Coal

Figure 10. Evaluation of Flame Stability by Measurement of Spectrum Intensity Emitted from Coal Flame



(a) Mother Coal

(b) Blended Coal

Figure 11. Effect of Air Staging on Flame Stability

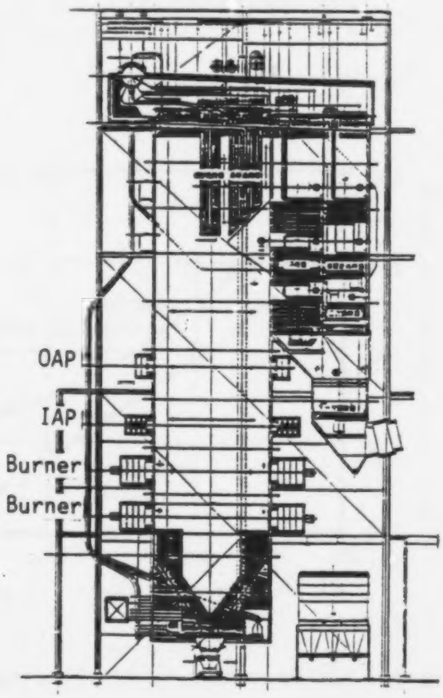

OAP
IAP
Burner
Burner

Figure 12. General Arrangement of a 530 T/H Boiler

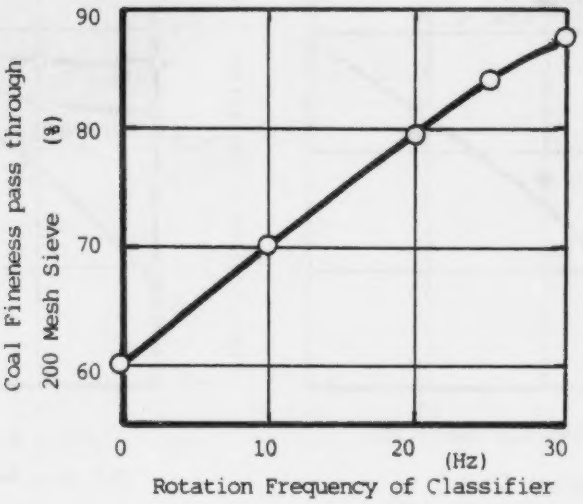


Figure 13. Relation between Rotation Frequency of Classifier and Coal Fineness

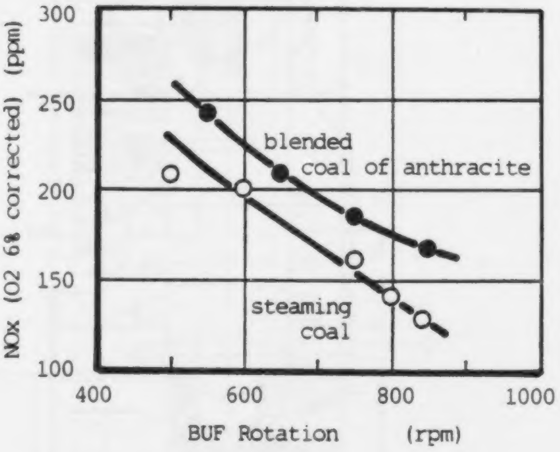
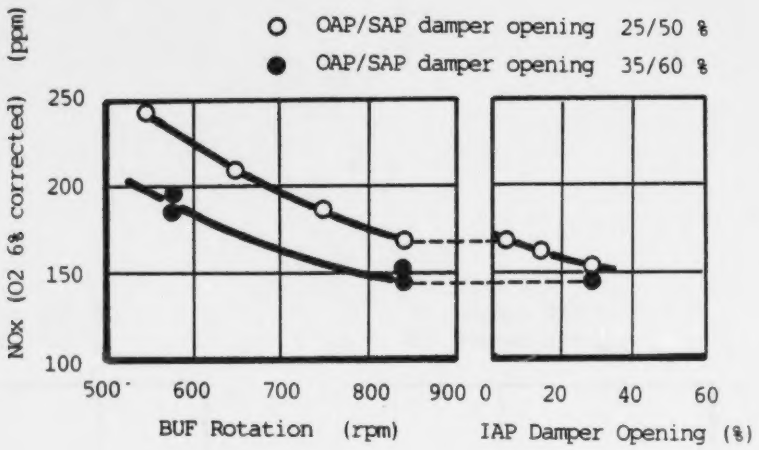
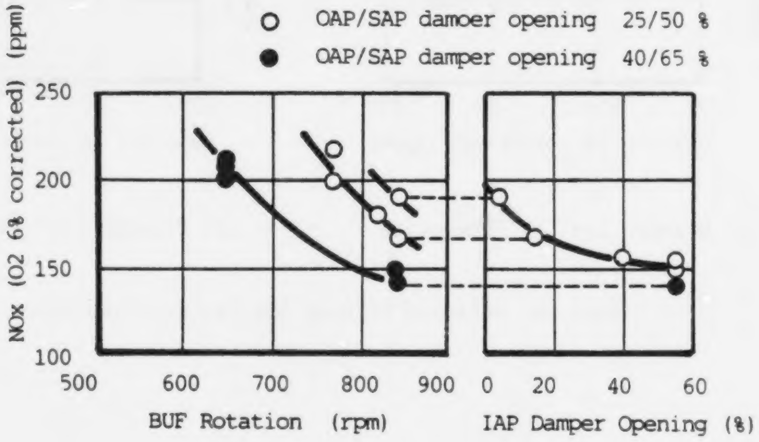


Figure 14. NOx Reduction by Air Staging through OAP/SAP Ports, expressed as a parameter of BUF rotation

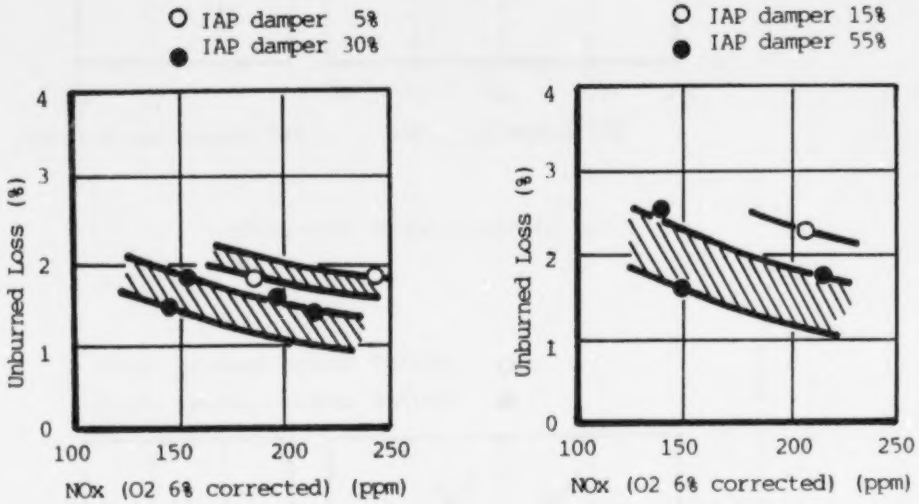


(a) Blended Coal of Anthracite



(b) Blended Coal of Petroleunm Coke

Figure 15. NOx Reduction by Air Staging through IAP Ports for Multi-air Staging of INPACT Method



(a) Blended Coal of Anthracite

(b) Blended Coal of Petroleum Coke

Figure 16. Relation between NOx Emission and Unburned Loss

Table 1

COAL PROPERTY
(for fundamental study)

Coal		A	B	C	D	E	F	G	H
HEATING VALUE*	(MJ/kg)	27.9	28.3	18.3	20.6	29.1	27.72	31.15	30.56
Proximate Analysis*									
Inherent Moisture	(%)	2.9	3.1	22.8	22.0	3.7	2.1	1.1	3.5
Volatile Matter	(%)	29.5	26.2	34.1	41.0	31.0	22.9	20.1	9.1
Fixed Carbon	(%)	51.6	56.7	32.2	34.7	49.8	57.7	69.0	77.2
Ash	(%)	16.0	14.0	10.9	2.1	15.5	17.3	9.8	10.2
Ultimate Analysis**									
Carbon	(%)	69.2	71.7	60.5	67.3	71.0	70.8	80.3	82.1
Hydrogen	(%)	4.5	4.3	4.1	4.3	4.7	3.9	4.7	3.3
Nitrogen	(%)	1.5	1.5	2.0	1.0	1.4	1.3	1.1	1.7
Sulphur	(%)	0.3	0.6	2.1	0.0	0.5	0.3	0.3	0.6
Oxygen	(%)	8.0	7.4	17.2	24.2	6.4	6.1	2.7	1.7

Note: Coal A, B, C, D and E were used for the research using a reactor tube, and Coal E, F, G and H were burned at a tunnel type test furnace.

* Air dry basis

** Dry basis

Table 2

COAL PROPERTY
(for field test)

Coal or Coke		Steaming Coal	Anthracite	Petroleum Coke
Heating Value*	(MJ/kg)	29.35	29.31	35.84
Proximate Analysis*				
Inherent Moisture	(%)	3.8	2.0	0.6
Volatile Matter	(%)	34.7	11.0	12.8
Fixed Carbon	(%)	51.9	74.0	86.4
Ash	(%)	9.6	13.0	0.2
Ultimate Analysis**				
Nitrogen	(%)	1.5	1.8	1.0
Sulphur	(%)	0.6	1.9	4.9

* Air dry basis

** Dry basis

Session 4

MANUFACTURER'S UPDATE

Chairman: G. Offen, EPRI

The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

NOx CONTROL: THE FOSTER WHEELER APPROACH

Joel Vatsky
Director, Combustion and Environmental Engineering
Foster Wheeler Energy Corporation
Perryville Corporate Park
Clinton, N.J.

INTRODUCTION

The approach to achieving low NO_x emissions, employed by Foster Wheeler Energy Corp., is based upon utilizing low NO_x burners as the primary control method. The Controlled Flow/Split-flame low NO_x burner has been in field service on industrial units since 1976 and in utility service since 1979. It has been employed as original equipment on new steam generators and has been retrofitted to several industrial and utility units.

A major advantage of this burner is its flame shape which is similar to that of pre-New Source Performance Standards turbulent burners. Consequently, it has negligible effect on radiant zone absorption patterns and furnace exit gas temperature. As such it has been installed on pre-NSPS units and not degraded boiler performance or efficiency.

The CF/SF burner can be installed on any wall-fired steam generator whether originally equipped with circular or cell-type burners. It can be retrofitted on most circular burner equipped units with no pressure part or structural modifications (eg. as a "plug-in") simply replacing the existing secondary air register and coal injectors with the new designs.

Typically, NO_x can be reduced by 50%, although reductions of up to 60% have been attained, without simultaneously utilizing supplemental NO_x controls such as staging ports. Experience to date indicates that percent NO_x reduction is not strongly dependent on fuel characteristics, although absolute NO_x level is.

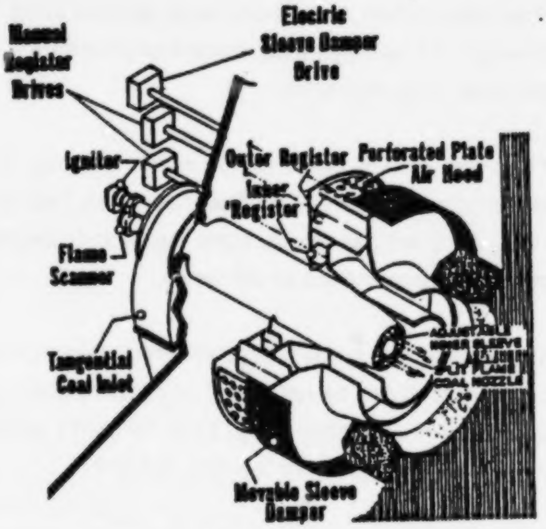
Significant additional NO_x reductions, up to a total of 80%, can be attained by combining a modern overfire air system with the CF/SF burner. Field tests in the early 1980's on two utility steam generators, and subsequent evaluations on our 80 million Btu/Hr Combustion and Environmental Test Facility, have demonstrated NO_x levels below 0.2 lb/million Btu.

This paper describes the low NOx systems and summarizes the field and developmental results.

CONTROLLED FLOW/SPLIT-FLAME LOW NOx BURNER

Foster Wheeler chose to develop a low NOx burner based on internal staging characteristics (i.e, fuel and air staged within the burner while retaining historical flame shapes) rather than utilize delayed combustion (long-flame) or external staging (tertiary air port) burner concepts. The internally staged CF/SF concept does not adversely affect either heat absorption profiles of the furnace, the FEGT or the furnace structure as can the delayed combustion concept or the externally staged concept, respectively.

The Controlled Flow/Split-flame low NOx burner, shown schematically in Figure 1, is a dual register design with the registers arranged in series. The inner register controls the swirl and stoichiometry around the coal injector while the outer register affects the flame envelope's shape.


Manual Register Drives
Electric Sleeve Damper Drive
Igniter
Flame Scanner
Tangential Coal Inlet
Outer Register
Inner Register
Perforated Plate Air Hood
Adjustable Inner Sleeve
Split Flame Coal Nozzle
Movable Sleeve Damper

Controlled Flow Split Flame Burner
Figure 1

Surrounding the register assembly is a perforated plate air hood which improves the circumferential distribution of secondary air entering the outer register. By measuring the pressure drop across each burner's perforated plate, an index of the secondary air flow can be obtained. This index aids in balancing burner stoichiometries to minimize excess air requirements. Therefore, since secondary air distribution within the windbox is optimized, the common windbox can be retained and there is no need to modulate burner air flow controls.

The coal injector consists of a tangential scroll inlet, annular fuel barrel and split-flame nozzle with axially movable inner tip. Adjusting the inner tip will vary the primary air/coal mixture's velocity so that it can be optimized with respect to the secondary air.

Control of the primary air/coal distribution and velocity is an integral part of achieving low NO_x levels with acceptable flame conditions. The coal is collected into four concentrated streams which yield substoichiometric flames in the near-throat region while the burner operates at normal excess air levels.

Advantages of the CF/SF low NO_x burner design, which enhance its attractiveness for use on retrofitted boilers as well as new units, include:

(1) Does not rely on long, narrow delayed mixing flame to achieve low NO_x.

(2) Fully compatible with existing burner management, flame scanning and ignition systems.

(3) "Plug-in" retrofitability: No pressure part or structural modifications are required for burner installation.

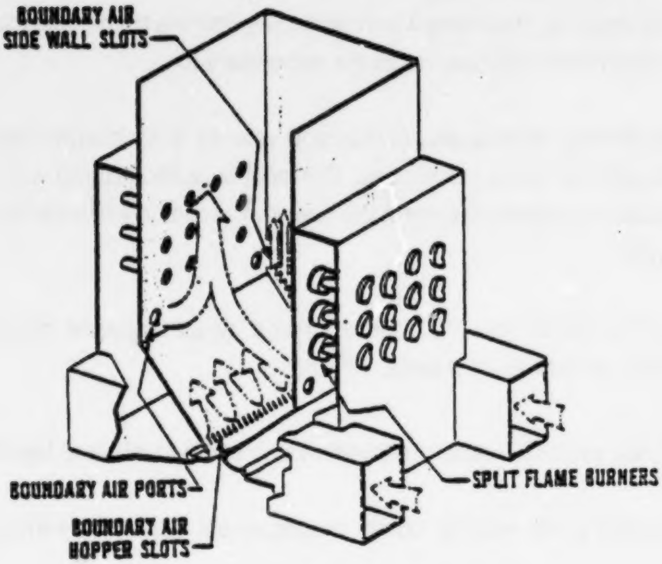
(4) Same burner pressure drop as historically used with turbulent burners (2-4" H_20).

(5) Independent control of secondary air flow and swirl at each burner thus allowing air/fuel ratio to be optimized at each burner without modifying swirl; and without modulating secondary air flows.

In addition to the low NO_x burners, a set of Boundary Air ports, requiring a total of four openings in the tubewalls for opposed fired units, is offered. Their location is schematically shown in Figure 2. The ports inject windbox air along the sidewalls in order to produce a high excess O_2 concentration which will not vary significantly as pulverizers are taken in and out of service over the boiler's upper load range. In combination with the burner's ability to adjust secondary air flow distribution both vertically and horizontally within the windbox, the boundary air system is intended to maximize the overall flexibility to control oxygen distribution during combustion.

EMISSIONS DATA

A substantial body of operational and emissions data for industrial and utility steam generators, equipped with the CF/SF burner, has been obtained over the past ten years. Some of the more interesting results are those obtained on steam generators designed for use with turbulent burners and subsequently retrofitted with the CF/SF low NO_x burner.



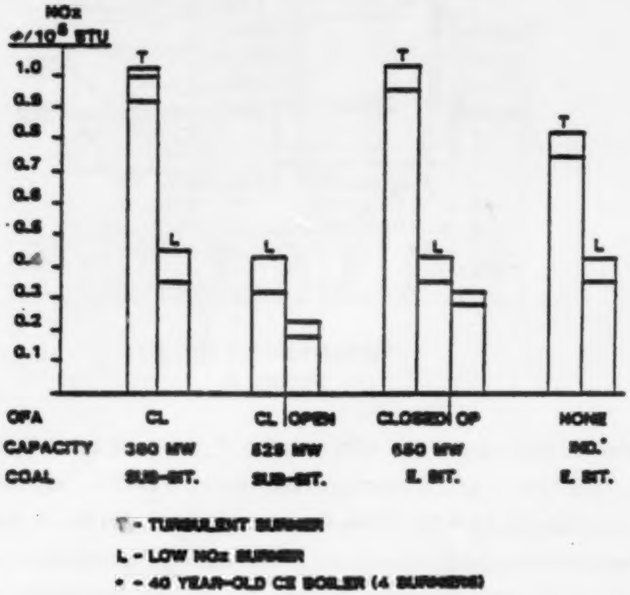
Boundary Air System
Figure 2

In 1984 a retrofit was made to a 110,000 lb/hr 4-burner steam generator at a Du Pont chemical plant in Martinsville, Virginia; primarily for the purpose of demonstrating SO_2 control via sorbent injection. The demonstration was funded by Consolidation Coal Company; FWEC's part being the supply of low NO_x burners with integral limestone injectors. NO_x was reduced 50% without any measurable change in Furnace Exit Gas Temperature as determined by FWEC's boiler performance program and in-situ HVT measurements performed by Conoco.

FWEC has also made several retrofits to utility steam generators. Figure 3 summarizes NO_x emission results from three utility units with the data from the 110,000 lb/hr Du Pont Martinsville unit included for comparison.

The first unit shown is the 360 MW San Juan #1 of Public Service New Mexico. When sold, after the 1971 State of New Mexico NO_x regulations took effect, it had to meet the new regulation of 0.45 lb/million Btu (in contrast to the Federal EPA limit of 0.7). However, when started up in 1976 FWEC's low NO_x burner had not yet been developed. Consequently, the unit was equipped with turbulent burners with NO_x control via overfire air only. Emissions were about 0.95 lb/million Btu with OFA ports closed (and less than 0.7 with OFA ports open). The State of New Mexico Regulation (0.45) was not attainable.

San Juan #1 was retrofitted with Controlled Flow/Split-flame low NO_x burners in 1979 with NO_x reduced to about 0.4 lb/million Btu, without overfire air. Subsequent to this success, which was a true retrofit, the CF/SF burner was installed on several units which were in the construction phase, in keeping with FWEC's policy of providing our newest technologies where practical. One of these units, all of which had been designed for turbulent burners, is a 525 MW steam generator. Data for this unit, with and without overfire air, is also shown on Figure 3. There are several other steam generators, retrofitted in the early 1980's while being constructed, ranging from 250 MW to 700 MW which show similar results. Most do not have overfire air ports and those which do have them do not need them to meet the relevant NSPS requirements.

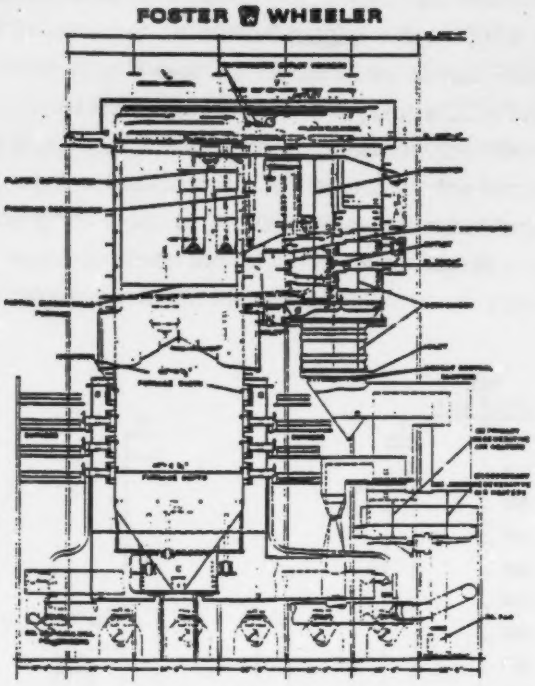


Low NOx Burner Retrofits
Figure 3

The most recent retrofit is the 650 MW unit also shown on Figure 3. This is the Pleasants Station Unit #2 of Allegheny Power Corp. The following section discusses this unit in more detail.

PLEASANTS UNIT #2 LOW NOx BURNER RETROFIT

Allegheny Power System's Pleasants Power Station has two identical Foster Wheeler supercritical once-through steam generators (Figure 4). These 5,035,000 lb/hr single reheat units supply steam to 626 MW (net) Allis-Chalmers turbine-generators and were designed to meet the requirements of the 1971 new source performance standards, which limit NO_x emissions to 0.7 lb/million Btu. They are equipped with wet scrubbers to control sulphur emissions.



Pleasants Unit No. 2
Figure 4

The steam generators were equipped with overfire air ports as the only means of NO_x control. NO_x emissions in Unit Nos. 1 and 2 averaged between 0.6 and 0.7 lb/million Btu after start-up in 1978 and 1980, respectively. Unit No. 2 has less margin than Unit No. 1, however, and as a result, Unit No. 2 experienced periodic derates to avoid exceeding the regulatory limit. It was determined that the best method of eliminating the derates due to NO_x limitations was to install low NO_x burners.

The Controlled Flow/Split-flame low NO_x burner was installed in Unit No. 2 during a four week outage in 1986. In addition to eliminating NO_x derates, it was anticipated that the new burners could help boiler performance in the following areas:

(1) Induced draft fan limitations - The ID fans were designed with insufficient capacity margins to accommodate some fuel/moisture/load combinations. The low NO_x burners operate with less excess air, thus providing greater capacity margin.

(2) Furnace sidewall corrosion - The low NOx burners with lower Boundary Air ports admit more combustion air in the furnace zone by eliminating overfire air thus providing more oxidizing air for the sidewalls.

(3) Air register maintenance - Reduced maintenance costs would result by not having to maintain air port and burner registers.

(4) Boiler efficiency - Improved boiler efficiency would result due to reduced dry gas loss resulting from low excess air operations.

The steam generator has 24 burners with 12 on each of the front and rear walls. Each of the six rows of four burners are supplied by a ball mill pulverizer. The unit has eight overfire air ports which were used to admit air for NO_x control.

The original intervane burners were removed so that the new low NO_x burners could be installed. The intervane burner is a basic design with one air register and the coal nozzle consisting of an inner and an outer barrel. Coal enters the annulus between the barrels tangentially through the scroll. The primary air/coal stream mixes with the secondary air in a highly turbulent manner.

The low NO_x system installed at Pleasants includes the low NO_x burners and boundary air ports which were installed in the four corners of the furnace above the ash hopper slope as shown in Figure 2. These air ports inject windbox air along the sidewalls in order to produce high O_2 levels between the wing burners and sidewalls, and is intended to reduce furnace sidewall corrosion that occurs when a local reducing atmosphere exists in this region.

An important feature of the low NO_x system is the ability to reduce overall excess O_2 levels. This can be achieved because of the ability to balance burners in the windbox and by closing the overfire air ports. In order to be able to determine this minimum excess O_2 level, carbon monoxide (CO) monitors were added to the unit. It was felt that the O_2 could be lowered to a point before CO appeared in unacceptable levels, providing that no other adverse conditions existed (e.g., severe slagging, sidewall wastage).

The low NO_x burner system was installed during a four-week outage that occurred in February, 1986. The burners were designed so that no pressure part modifications were necessary in the burner throat area. The existing burners, air registers, and scrolls were removed. The new air register assemblies, inner and outer barrels were installed and the existing scrolls were reused. Modifications to the outer windbox wall were completed to accommodate the new manual actuators, to reposition the main register drive motors. A modification was done to the burner refractory that involved removal of some refractory, leaving a leaner profile. This was intended to reduce the chances of slag accumulations, or "eyebrows." During this outage, the overfire air ports were repaired and left operable in case overfire air was needed to meet the lower NO_X performance guarantee. However, the overfire air ports have not been used since the installation of the low NO_X burners.

Emission Test Results

The Pleasants No. 2 unit was originally brought into commercial operation in 1981. Installed within the common windbox, as shown in Figure 4, the overfire air dampers remove secondary air from the burners in order to decrease burner stoichiometry. This design was set to produce an NO_X margin of about 10% below the guarantee level, based on the contract performance coal. However, NO_X emissions will vary with coal constituents, load, excess air and the number of pulverizers or burners out of service. With this configuration, burner register position will also affect NO_X, primarily by changing windbox pressure which modifies the amount of overfire air flow.

Figure 5 compares the NO_X emission results as a function of excess O_2 for the turbulent intervane burners with and without overfire air. This data, taken during and shortly after the initial start-up,

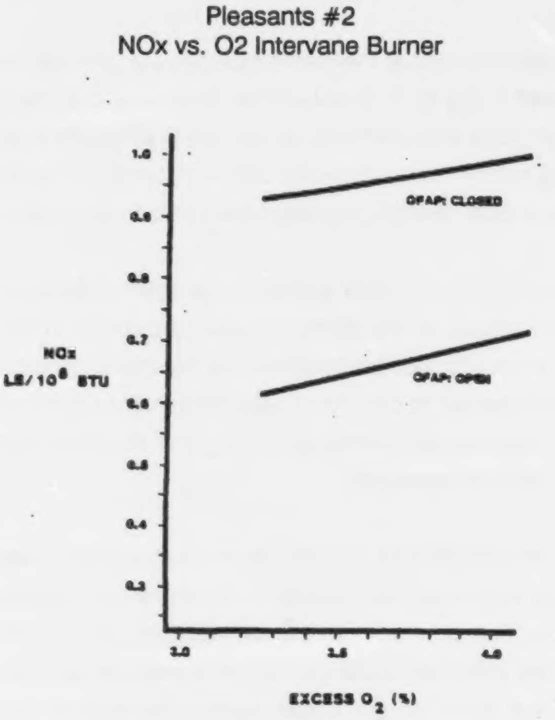
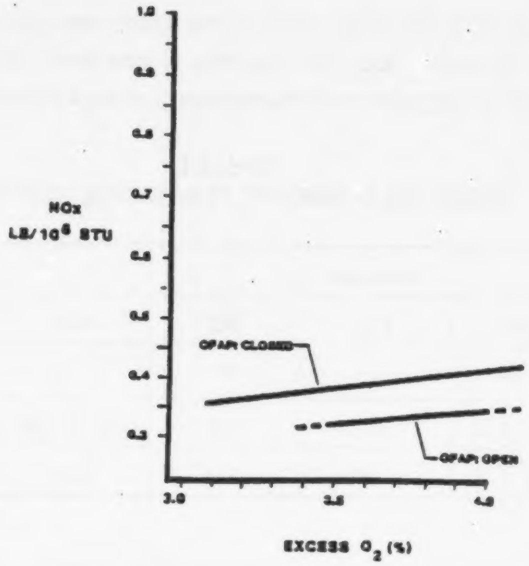

Pleasants #2
NOx vs. O2 Intervane Burner

Figure 5

was typical of subsequent operation. Although there were periodic incidents requiring unit load to be reduced in order to prevent NOx exceeding the regulatory limit as indicated by the stack monitor, checks by both FWEC and independent test contractors confirmed the lower curve of Figure 5.

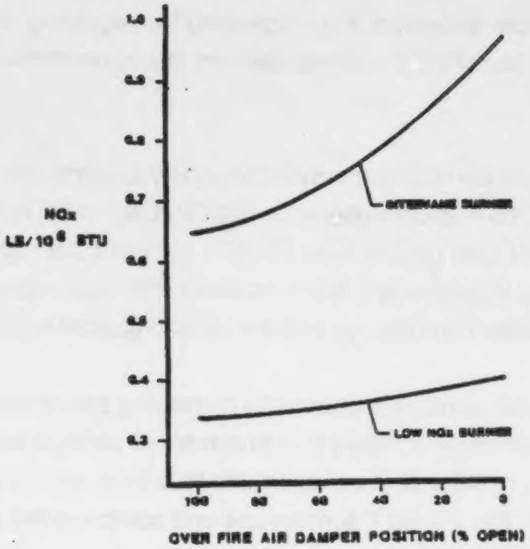
After installation of the low NOx burners and boundary air ports, during a four week January/February, 1986 outage, start-up commenced in late February. Initial burner settings (inner and outer register and movable coal nozzle) were FWEC's standard start-up positions. After reaching full load with all burners in service and with overfire air and boundary air ports closed, it was found that the NOx level was in compliance with the revised guarantee, 0.6 lb/10^6 Btu.

A two-week burner optimization and low NOx monitoring period was undertaken. This produced the NOx results summarized in Figure 6. With overfire air ports closed, NOx was reduced to about 0.4 lb/10^6 Btu. With overfire air ports open, the NOx level, during test conditions, was reduced to about 0.33 lb/10^6 Btu. Figure 7 summarizes and compares the performance of the intervane and low NOx burners as a function of overfire air port damper position: NOx is reduced a total of 67% from the completely uncontrolled condition.



Pleasants No. 2-NOx vs. O2 Low NOx Burner
Figure 6

Table I summarizes typical flue gas measurements for the two burners. Unburned carbon loss, being a key measure of efficiency, was measured after the low NOx burners were optimized. As



Pleasants No. 2 - NOx vs. OFA
Figure 7

shown on Table I, the unburned carbon level in the flyash was below 2.5% (measured in a loss on ignition test). For the coals used, this translates to less than 0.35% as efficiency loss, which is within the normal range for pulverized bituminous coal-fired boilers.

TABLE I.
EMISSION SUMMARY: PLEASANTS UNIT NO. 2

Burner	Intervane			Low NOx		
	NOx	CO	UC	NOx	CO	UC
Units	lb/10^6	ppm	%			
OFA: Closed	0.95 ± 0.05	40	2.5	0.41 + 0.02	40	2.5
OFA: Open	0.65 ± 0.05	40 - 60	2.5	0.33	100	--

*No data was taken as this was a short-term test condition designed only to observe NOx change.
+Measured at economizer exit.

The fuel in use at the station is a middle Kittanning high volatile bituminous coal. Table II compares the contract boiler performance coal with the fuel used during the 1981 start-up and shakedown and the fuel currently being burned.

TABLE II.
COAL ANALYSIS: PLEASANTS STATION

Constituent	Performance	1981	1986
FC/VM	1.36	1.31	1.45
N_2	1.0	0.9	1.3
FC	43.6	47.9	50.4
VM	32.1	36.6	34.7
Ash	16.8	13.6	11.7
H_2O	7.5	2.3	3.2
C	62.3	69.4	7.0
H	4.1	5.1	5.0
O	5.1	6.4	5.4
S	3.2	2.7	3.4
HHV (Btu/lb)	11,500	13,600	12,700

The most significant differences between the current fuel's characteristics and those of the earlier fuel are:

- Increase in fixed carbon to volatile matter ratio of about 10% (1.31 to 1.45)
- Increased fuel nitrogen content of about 40% (0.9 to 1.3)

Both of these changes would tend to increase NO_x emissions, all other factors being equal.

Operational Results

In parallel with achieving low NO_x levels is the importance of not degrading steam generator performance and efficiency, nor of creating operational difficulties for the station's personnel.

Areas of particular concern are discussed below, along with actual observations:

(1) Burner Pressure Drop: Any increase in burner resistance, either on the primary or secondary air side, would result in higher power consumption.

- Primary air fan power consumption is in the same range as with the original coal injectors, indicating no significant change to nozzle flow resistance.
- Windbox-to-furnace pressure drop is the same as before: at full load with all burners in service and overfire air ports closed ΔP is about 3.0 - 3.5" H_2O.

With OFA open, it is approximately 1.5" H_2O, both at normal excess air of 20% (3.6% O_2).

(2) Furnace Exit Gas Temperature: Some types of low NOx systems rely on long, delayed mixing flames which have the potential for increasing FEGT. If this were to occur on the Pleasants unit, the resulting increase heat head across the convection pass would cause:

- Higher spray flows to control superheater temperature
- Shifts in reheat control damper positions (the unit uses a parallel pass convection arrangement for reheat control) to prevent high reheat temperatures. Higher air heater inlet temperature could also result.

None of these potential adverse effects have been noted over the past 14 months of low NO_x burner operation. Consequently, the absorption patterns which can be observed and measured with normal steam generator performance techniques show no change due to the low NO_x burners.

3. Slagging and Fouling: Since the coal can be classified as having a medium to high slagging potential, additional ash deposition would be of concern, particularly during low NOx firing.

- Furnace Slagging: With the original burners, the walls were covered with a thin, light coating of ash. However, very large "eyebrows," up to 6' in length, would form over the burner throat openings. In many cases, the flames would be burning through a "tube" of slag. The burner throat refractory modifications made during low NO_x burner installation have resulted in the eyebrows being reduced in size to the point where they no longer affect the flame or cause other adverse impacts.

  Ash coverage on the walls is essentially the same as before. The visual observations made are somewhat subjective since there is no adequate means of directly quantifying ash extent and quality. However, the thermal measurements discussed in (2) above also confirm that there has been no increase in furnace deposition. A significant increase in furnace wall coverage would reduce absorption in this region thereby causing high FEGT with previously noted adverse consequences.

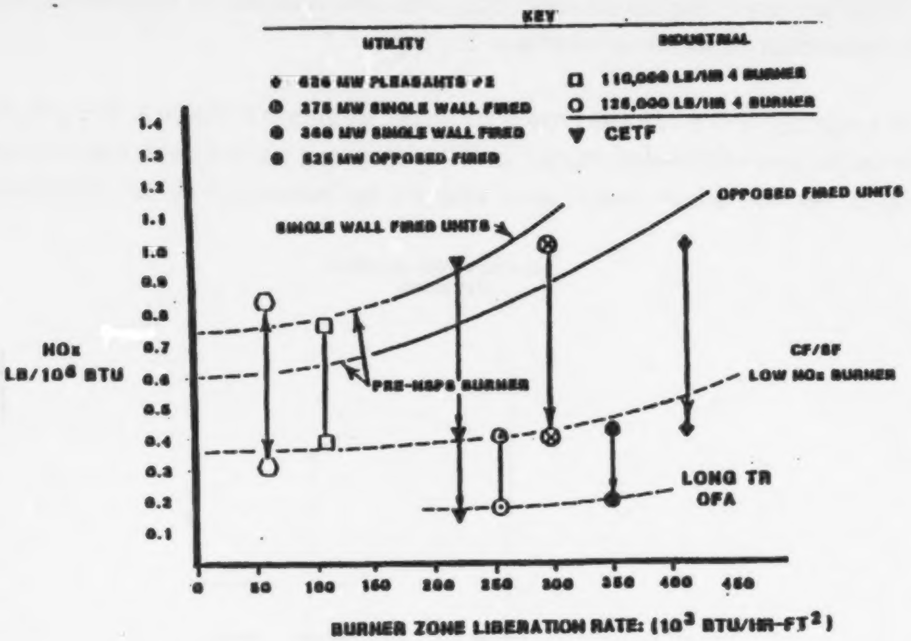
- Fouling: Visual observations and evaluation of the thermal measurements indicate no increase in superheater fouling or convention pass deposition. Again, this implies that extended flames and upper furnace combustion have not occurred.

Thus, after three years of operation, there have been no unsatisfactory or adverse side-effects resulting from the low NO_x burner retrofit.

FIELD DATA COMPARISONS

NO_x emissions from coal combustion consist of two components: thermal fixation of atmospheric nitrogen and conversion of fuel-bound fixed nitrogen to NO. Furnace thermal conditions will affect thermal NO_x generation while burner type will affect both thermal and fuel NO. Foster Wheeler has determined the characteristic relationships between NO_x emissions, furnace configuration and combustion intensity as represented by the Burner Zone Liberation Rate (BZLR is a measure of the heat input to the burner zone, the higher this value the higher the furnace temperature).

Figure 8 is a summary of NO_x emissions from turbulent and low NO_x burners. The upper two curves represent the variation of NO_x with BZLR for single wall and opposed fired units equipped with intervane burners. The bottom curve is for the CF/SF low NO_x burner. Data from industrial and utility units and FW's test facility (CETF) are shown. There is very good correlation between data points and predictive curves.



NOx Reduction Summary
Figure 8

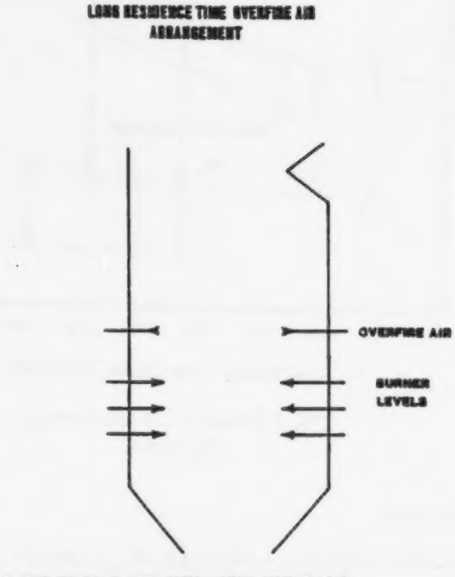
ADVANCED OVERFIRE AIR

Foster Wheeler has been investigating advanced NO_x control measures for new unit and retrofit use. Some technologies which can be relatively easily incorporated into a new steam generator cannot be economically retrofitted to pre-NSPS units.The following summarizes an advanced overfire air technique for achieving lower NO_x levels than are achievable with conventional methods.

Conventional overfire air systems, as presented above, utilize approximately 20% of the total combustion air flow with ports located above the top burner level. Under these design conditions NO_x reductions of about 30 - 35% are achievable. Although greater reductions are obtainable by using more overfire air (lowering the burner stoichiometry) the potential adverse side-effects of such large OFA quantities generally preclude their use.

However, it has been determined that improved NO_x reduction can be attained by increasing the distance between the overfire air level and the top burner level, thereby increasing the residence time in the stoichiometric flame for reactions which reduce NO to N_2 to occur. This concept was field demonstrated in the early 1980's on two utility steam generators which had been retrofitted with CF/SF burners during construction. Both units were designed for future lignite firing and, as such, were equipped with an extra level of burners.

The arrangement of one of these units is schematically shown in Figure 9. The units fired much higher quality coal when initially started up. When operating with the overfire air ports closed and the top burner level out of service, at full load, the top burners act as conventional overfire air

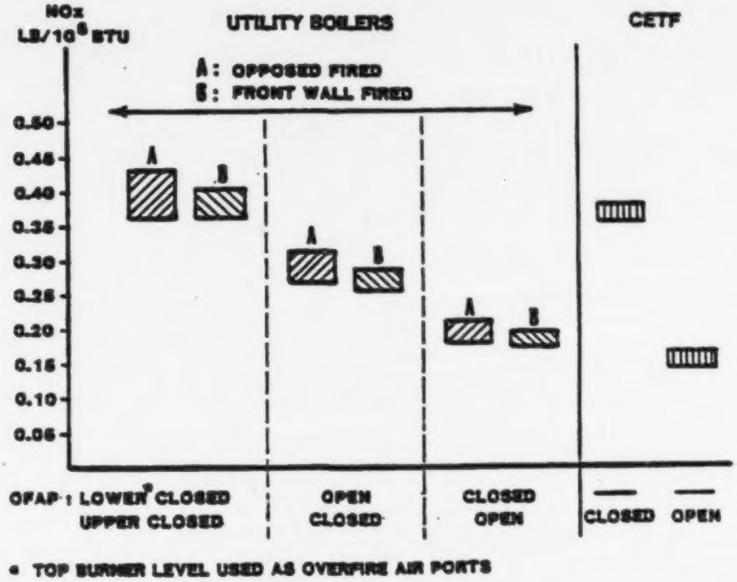

LONG RESIDENCE TIME OVERFIRE AIR ARRANGEMENT
OVERFIRE AIR
BURNER LEVELS
UNIT EQUIPPED WITH EXTRA LEVEL OF BURNERS CAN BE USED AS OVERFIRE AIR

Long Resident Time Overfire Air Arrangement
Figure 9

ports. When the top burner's registers are closed the overfire air ports are used the residence time is significantly increased over that of the conventional overfire arrangement.

More recently, FW has started up an 80 million Btu/hr Combustion and Environmental Test Facility. The CETF furnace in equipped with overfire air ports located well above the top burner level.

Figure 10 summarizes the effect of increased OFA residence time on the two utility boilers (data from 1981 and 1982) and the CETF (data from 1986). The results are consistent in that the increased residence time yields a NO_x reduction nearly double that of the standard ports: 50% vs. 30%.



Effect of OFA Resident Time
Figure 10

These very encouraging results have enabled Foster Wheeler to provide such systems on new and retrofit applications to utility steam generators.

SUMMARY

Foster Wheeler has obtained considerable experience with commercial low NO_x burners on both new steam generators and retrofitted units. Emission and boiler performance results are consistent in that NO_x is typically 50 - 60% lower than with pre-NSPS turbulent burners and there have been no indications of adverse effects on boiler performance or operation due to the low NO_x burners. Of particular significance have been the successful retrofits of industrial and utility units ranging in size from 110,000 lb/hr to 650 MW.

Advanced combustion-based NO_x controls combining a commercially-proven low NOx burner with a modern overfire air system can achieve NOx reductions up to 80% from pre-NSPS levels.

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NO_x CONTROL UPDATE - 1989

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ABSTRACT

Babcock & Wilcox is actively expanding its technology base and product lines for controlling NO_x emissions in the combustion process or, thereafter, in existing and new boiler applications. Fuel economics and extremely low emission limits in some locations are causing a resurgence in natural gas and fuel oil low NO_x systems. In retrofit situations, compact furnaces and crowded boiler settings complicate the addition of NO_x control equipment. B&W has recently developed the XCL Oil/Gas Burner which makes use of air and fuel staging principles in the burner, resulting in very low NO_x emissions without addition of gas recirculation systems or NO_x ports. The PG-Dual Register Burner offers broad commercial experience in combination with more traditional NO_x control measures for use with oil or gas. With regards to pulverized coal, the XCL-PC Burner is operating successfully in its first commercial application in the EPA's LIMB project. The XCL-PC is capable of even lower NO_x emissions than its predecessor, and flame shape can be tuned to accommodate furnace dimensions. Development of the Low NO_x Cell-PC Burner is complete and the first demonstration will also include gas and oil capabilities.

Application of reburning to a coal-fired cyclone unit proved to be quite successful at B&W's research facility and negotiations are underway to commercially demonstrate this technology. Atmospheric and pressurized fluid beds offer low NO_x emissions for new plants or repowering. An updated overview is provided here of the systems used by B&W to control NO_x emissions in the above and other situations.

INTRODUCTION

All new steam generating units in excess of 100 million Btu/hr (MKB) input firing gas, oil, or coal in the United States are subject to federal New Source Performance Standards (NSPS) regulating NO_x emissions. These units may also face more stringent NO_x requirements enacted by state legislation. In addition, new units must comply with permitting requirements under provisions of the federal Clean Air Act, for attainment or non-attainment regions as applicable. Limits much lower than NSPS are becoming more common for new units. Existing sources are subject to restrictions in non-attainment regions, either directly or to provide offsets to permit operation of new units in that region. Still, the majority of pre-NSPS units are not presently subject to NO_x limitations. Public, congressional, and international debate over the need for emission limits on these units seems to be nearing a decision point, with enactment of Acid Rain Legislation appearing imminent. Acid Rain Legislation will most likely restrict emissions of NO_x and SO_2, particularly from units in the central and northeastern U.S. In summary, new units are increasingly being regulated to NO_x emission limits much below federal NSPS, and many unregulated existing units are likely to be subject to NO_x limitations in the near future.

Babcock & Wilcox (B&W) is a leader in the development and commercial application of systems to reduce emissions of NO_x from industrial and utility steam generating equipment. B&W's NO_x control program began in 1957, with the company receiving the patent (U.S. Patent No. 3048131) for two-stage combustion shortly thereafter. The program has continued to grow for over 30 years, in depth of technology and in diversity of application. B&W low NO_x systems are reducing emissions from over 40,000 MWe of utility steam generators in the U.S., plus a wide range of industrial units. Technologies range from multi-fuel staged wall-fired burners for new and existing boilers, to repowering with pressurized fluid bed boilers.

This paper will describe systems offered by B&W to control NO_x emissions from utility and industrial scale steam generation equipment. The emphasis will be on control of NO_x during the combustion process but post-combustion NO_x control systems will also be considered.

Some of the systems which will be discussed are being developed to facilitate significant NO_x reductions on existing units which are not amenable to standard NO_x control measures e.g. the Low NO_x Cell Burner and reburning systems for coal-fired cyclone boilers. Other systems have a broad range of application to existing or new steam generating equipment. The discussion which follows is organized by fuel forms--solids, liquids, gas--due to the widening variety of solid fuels of interest and due to a narrowing of distinctions between systems once considered either utility or industrial.

SOLID FUELS

PULVERIZED COAL

Dual Register Burner

Pulverized coal remains the dominant fuel for electric power production in the United States. B&W's first low NO_x PC-fired burner was developed and commercialized in the early 1970's--the Dual Register Burner (DRB). The DRB differed from conventional wall-fired circular burners by its axial fuel injection arrangement and dual concentric registers for increased control of swirl and air/fuel mixing (Figure 1). The DRB is used in combination with a compartmented windbox and enlarged combustion zone, and occasionally with NO_x ports. This system has successfully met all applicable NO_x emission limitations, ranging from 0.7 to 0.45 lb NO/million Btu (lb/MKB). Actual emissions from coal-fired units with DRBs range from 0.7 to 0.3 lb/MKB.

Emission levels are a function of coal properties, stoichiometry, and burner/furnace design for a particular unit. The DRB typically achieves 40 to 50 percent reduction in NO_x from uncontrolled levels. This differentiates the DRB from other low NO_x burners which rely on Over Fire Air, Under Fire Air, Boundary Air, etc. to augment NO_x performance. The DRB reduces NO_x by virtue of its air/fuel mixing characteristics, avoiding the expense and slagging/corrosion problems associated with staging air ports in coal-fired units. All of the 68 units in service with DRBs satisfy applicable NSPS without use of air staging systems. The adaptability of the design is shown in Table 1, with experience totaling over 37,000 MW and including lignites, subbituminous, and bituminous coals.

The Enhanced Ignition Burner (Figure 2), a modified DRB, is used with low volatile coals or lower grade lignites. Ignition performance and flame stability are improved with these "difficult" coals by reduced fuel jet momentum and increased recirculation of hot gases by the Enhanced Ignition Burner. A resulting increase in NO_x can be offset by NO_x ports when necessary.

XCL Burner

The XCL Burner is the most recent addition to the DRB family. The XCL's functional performance is an outgrowth of Babcock Hitachi's HT-NR Burner and its predecessor, the B&W DRB (1). Like the HT-NR, the XCL Burner (Figure 3) reduces NO_x emissions even more effectively than the DRB, typically 25 percent lower, by virtue of fuel staging reactions promoted by the design. But the XCL Burner is designed to facilitate use in retrofit applications by three features. One, the very low NO_x emission levels of the burner permit its use without addition of NO_x ports, even in the smaller furnaces of pre-NSPS units. Two, the flame shape can be tuned to fit the furnace by use of impellers as appropriate. For furnaces with limited depth e.g. single wall-fired units, flame length is reduced to avoid opposite wall impingement and maintain high combustion efficiency. Larger opposed-fired units, with hotter combustion zones, will usually not need impellers and benefit from lower NO_x performance of the XCL. Figure 4 compares flame length and NO_x versus burner input for B&W circular burners (pre-NSPS/high NO_x) and XCL Burners with and without impellers. Combustion tests reveal the flame length versus burner input for the XCL with impeller is equivalent to another manufacturer's low NO_x burner, although NO_x is somewhat lower with the XCL. Three, the XCL is configured for use in wall-fired units without requiring compartmented windboxes. Air flow control, measurement, and swirl adjustment functions are separated and provided for each individual burner. This enables precise tuning during commissioning for higher levels of performance. The mechanical design is adapted from B&W's S-Burner. The S-Burner solved problems with overheating, warpage, binding, etc. experienced by other burners, providing reliability and sustained performance in hostile operating conditions. A full complement of XCL Burners were retrofitted to Ohio Edison's Edgewater Station, Unit 4, in September 1986 as part of the Limestone Injection Multistage Burner (LIMB) demonstration. The unit continues to operate with NO_x emissions of 0.5 lb/MKB and well under one percent unburned carbon loss, on this 30-year-old single wall-fired boiler.

The XCL-PC Burner has recently been equipped with gas and fuel oil capabilities (2). Full scale prototype combustion tests (120 MKB/hr) demonstrated advantages of in-burner fuel staging techniques with these fuels producing very low NO_x emissions. Refer to the Fuel Oil and Gas Section of this paper (or Reference 2) for further information.

Low NOx Cell Burner

The Low NO_x Cell Burner was developed by B&W, with EPRI support, to replace standard two-nozzle cell burners which are in use in over 23,000 MW of capacity in the U.S. The Low NO_x Cell is designed to fit the wall opening of the existing standard cell, cutting outage time and expense otherwise required for pressure part replacement. The Low NO_x Cell is capable of reducing NO_x by 50 to 75 percent, as established by pilot and large scale combustion testing (3). This performance is achieved by virtue of the dedicated overfire air port incorporated into the upper port of each cell (Figure 5). A "Y-branch" combines the original two fuel pipes into one larger pipe which feeds the single enlarged nozzle in the lower throat. This design serves to minimize alterations to the coal piping. Flame shape is controlled by the impeller at the exit of the fuel nozzle, and by adjustable vanes in the lower and upper throats.

Future NO_x legislation notwithstanding, many utilities equipped with the original B&W cell type burners have already, or are currently considering, upgrading their burner hardware to improve mechanical reliability. Reliable mechanical operation of the burners permits burner adjustments to be made to improve distribution of secondary air within the wrap-around windbox. Some utilities equipped with cell burners are experiencing accelerated corrosion of the furnace sidewall tubes due to poor secondary air distribution. Lack of proper burner register control does not permit adjustments to correct this problem. The B&W S-type Burner, while not a low NO_x burner, has been retrofitted to numerous cell burner units in the past few years, to solve these problems. This burner is also compatible with the existing cell burner configuration and has been proven very reliable from a mechanical standpoint. Hardware features that make the S-type Burner mechanically superior and commercially attractive were incorporated in the design of the Low NO_x Cell Burner. In fact, the S-type Burner can be configured initially to permit future conversion to a Low NO_x Cell design with minimal changes to burner hardware (Figure 6). Utilities can therefore address immediate concerns regarding mechanical burner upgrades and reduce future costs associated with converting the unit to low NO_x operation. A full unit retrofit of 80 "convertible" Low NO_x Cell Burners has been in service since March of 1987, and has resulted in reductions of excess air and unburned carbon in this unit.

The Low NO_x Cell Burner can also be designed to accommodate oil and/or natural gas firing. A full unit retrofit of 15 Low NO_x Cell Burners capable of firing coal, oil, and gas will be demonstrated on one of ENEL's 320 MW units within the next year.

CYCLONE FURNACE

Crushed coal is being fired in cyclones of over 100 boilers, with utility generating capacity in excess of 26,000 MW. These units represent about 14 percent of pre-NSPS coal-fired generating capacity but produce about 21 percent of the NO_x emissions. There are currently no commercially demonstrated combustion technologies for cyclone boilers to reduce NO_x. Reburning technology is a promising alternative for achieving significant NO_x reduction in a cost-effective manner while maintaining unit integrity. Application of reburning to a cyclone unit is illustrated in Figure 7. Unlike other reburning systems, the lower furnace is operated at a stoichiometry over 1.0 to protect the cyclones and lower furnace from corrosion from the typically fired high sulfur coals. Other parameters are generally similar to other reburning applications.

Babcock & Wilcox is presently starting the final stage of a three-phase program to evaluate and commercially demonstrate reburning technology in cyclone-fired boilers. Phase 1 involved an EPRI/B&W sponsored engineering study which revealed that the majority of cyclone-equipped boilers could be adapted to this technology, with particular concern given to adequate residence times for the process. The study indicated a 50-70 percent NO_x reduction could be expected. The Gas Research Institute joined EPRI and B&W in Phase 2 of the project, in which pilot scale tests were performed in the cyclone-fired Small Boiler Simulator facility at the Alliance Research Center. Figure 8 depicts NO_x results as a function of reburning zone stoichiometry for coal, No. 6 oil, and natural gas reburning fuels (4). Baseline NO_x emissions of 925 ppm were reduced by 40 percent with coal/55 percent with gas at the higher reburning zone stoichiometry of 0.95. Increasing the reburning fuel at constant load to reduce reburning zone stoichiometry to 0.85 resulted in 68 percent NO_x reduction for coal and 75 percent for gas. Additional results of the pilot tests indicated no major boiler operational problems should inhibit commercial application of reburning technology to cyclone-fired boilers.

Consequently, Phase 3 of the program is in progress and involves full scale demonstration of coal reburning technology in Wisconsin Power & Light's 100 MW Nelson Dewey Station Unit 2. The performance goals are to reduce existing uncontrolled NO_x emissions by greater than 50 percent and exhibit no serious impact on cyclone combustor operation, boiler efficiency, fireside corrosion or deposition, and ash removal system performance. The contract for this 43 month project is presently being negotiated under the DOE Clean Coal II solicitation. The program is being supported by the Department of Energy, Wisconsin Power & Light, B&W, EPRI, the State of Illinois, and a consortium of utilities. Project initiation is anticipated for Summer 1989 with system start-up in Fall 1991.

FLUID BEDS

Atmospheric Fluidized Beds

Fluidized bed boilers can burn a variety of fuels while controlling both SO_2 and NO_x below federal emission limits. Fluid beds are differentiated as either bubbling bed or circulating (fast) fluid bed, depending on fluidizing velocity. The near term market for bubbling beds is primarily coal-fired retrofit applications for both industrial and utility boilers (5) (Figure 9). The driving forces are to reduce fuel costs (permit use of less desirable, lower cost coal), while avoiding slagging/fouling problems, and emission control. SO_2 is captured by calcined limestone bed material, with 90 percent capture capability with proper limestone selection and bed temperature. NO_x is controlled by low bed temperatures that discourage thermal NOX and reduce reaction rates for fuel NO_x. NO_x depends on the coal devolatilization rate and volatile content, excess air, bed temperature, CO and SO_2 concentrations and bed hydrodynamics. NO_x emissions of 0.3 to 0.4 lb/MKB are readily achieved without resorting to staging. Unburned combustibles exceed PC values, but depend on feed system design, coal type, bed temperature, superficial gas velocity, and recycle rate.

Circulating fluid beds (CFB) (Figure 10) are primarily used in new industrial and cogeneration units where a wide range of solid fuel firing is desirable (coal and/or biomass) (6). The combustion process of a CFB is particularly advantageous for difficult-to-burn fuels, such as coal waste. The CFB will usually reduce SO_2 and NO_x emissions and achieve lower unburned combustibles compared to a bubbling bed. SO_2 capture is improved by reduced sorbent particle size and increased sorbent residence time. The effect of these process variables is to achieve the required SO_2 reduction with lower Ca/S stoichiometry. NO_x is controlled by use of staging (primary/secondary air split) and low bed temperatures, to 0.3 to 0.4 lb/MKB typically.

Pressurized Fluid Beds

Pressurized fluidized bed combustion (PFBC) involves burning crushed coal under high pressure (150-250 psia) in a bed of limestone (7). The limestone captures 90 percent or more of the sulfur released during combustion. NO_x emissions less than 0.3 lb/MKB are a consequence of low bed temperatures (less than 1600°F) limiting formation; and increased bed depths with longer bed residence times, which serve to reduce NO_x from gases leaving the bed. The combined cycle power plant (Figure 11) is more efficient (10%) since the hot combustion gases drive a gas turbine which both pressurizes the system and produces electricity.

In 1985, B&W formed a partnership (ASEA Babcock) with ABB Carbon, formerly ASEA PFBC, of Sweden to supply pressurized fluid bed combustion systems. Through ASEA Babcock, B&W is presently involved in two major PFBC projects, both involving American Electric Power (AEP) and partially funded by DOE (Clean Coal Technology Program). The first contract is to supply equipment for a 70 MWe combined cycle PFBC demonstration plant to repower AEP's Tidd Plant. Hardware design is completed and fabrication is in the final stages. The boiler, cyclones, and other equipment are presently being installed in the 68-ft.-high, 44-ft.-diameter, 2 7/8-in.-thick combustor vessel. Start-up is scheduled for mid-1990. The second project is to repower a unit at AEP's Sporn Plant with a commercial 330 MWe PFBC system supplied by ASEA Babcock. DOE has selected the project for funding under Clean Coal II, and negotiations are in progress. Engineering is expected to commence later this year.

REFUSE SYSTEMS

At present, less than 10 percent of the refuse generated in the U.S. goes to refuse plants. New plants are being added at the rate of about 16,000 TPD of total capacity per year. The two categories of refuse combustion are mass fired and Refuse Derived Fuel (RDF) fired systems (8). Mass firing has been used exclusively with new "green field" refuse projects. Mass firing involves using refuse with minimal fuel preparation i.e. as received with large bulky items removed. Refuse is fed to a charging hopper and onto a reciprocating stoker where combustibles are burned off and ash is discharged. Compartmented undergrate air systems are used on modern units to even air distribution, with an overfire air system provided to improve combustion and maintain oxidizing conditions.

RDF firing is used in new "green field" projects, repowering projects (new boiler in existing plant), retrofit projects (converting to dedicated RDF boilers), or as a supplemental fuel. RDF is a higher grade fuel resulting from processing of refuse to remove and/or recycle a large portion of the non-combustibles. Modern RDF preparation systems employ conveyance, size separation, shredding, material recovery (iron, aluminum), density separation, and storage. The combustion system for a dedicated RDF boiler consists of overbed feeders supplying traveling grate stokers, equipped with underfire and overfire air systems. B&W's Controlled Combustion Zone (CCZ^{TM}) boiler is used to fire RDF or biomass (Figure 12). The twin furnace arches and overfire air systems provide much better mixing and flexibility to handle changes in fuel quality.

Refuse-fired boilers are not subject to NSPS limits for NO_x but are subject to provisions of the Clean Air Act which can require BACT in non-attainment regions, etc. Concerns about pollutants such as dioxins and furans have led to a strategy of optimizing combustion conditions to minimize their formation, as there is a correlation between low CO production and corresponding lower dioxin and furan emissions. Optimizing the combustion system for low CO has led to a slight increase in NO_x emissions. Typical refuse-boiler-emission levels are 200 to 350 NO_x and 50 to 100 CO (ppmvd @ 12% CO_2). Situations requiring lower NO_x emissions are resulting in use of ammonia injection systems or Selective Catalytic Reduction (SCR).

LIQUID AND GASEOUS FUELS

Activity levels are increasing for installation of low NO_x burners to fire gas and oil. Primary applications include main burners and auxiliary burners for new industrial-scale equipment. However, utility retrofit applications are beginning to increase, either in response to a variety of regulatory pressures, or to take advantage of the current attractive prices for these fuels. B&W offers several systems to reduce NO_x on oil- or gas-fired units. These are based on two types of Low NO_x Burners, the PG-DRB or the XCL. These burners can be augmented with other combustion-related NO_x control measures such as recirculated flue gas (GR), staging ports (NOx ports), or reburning, to further reduce NO_x emissions as the situation may warrant.

PG-DRB

The Primary Gas-Dual Register Burner (PG-DRB) was developed by Babcock Hitachi K.K. to improve NO_x reduction capabilities of the standard DRB. Over 11,000 MWe of generating capacity in Japan is operating with PG-DRBs firing gas or fuel oil. The distinguishing feature and name-sake of the burner is the use of "Primary Gas" (Figure 13). This term refers to recirculated flue gas routed directly to each PG-DRB, and introduced in a dedicated zone which surrounds the primary air zone in the center of the burner. The primary gas serves to reduce peak flame temperatures and oxygen concentration in the core of the flame to inhibit formation of thermal and fuel NO_x. The dual air zones surrounding the PG zone provide control of air/fuel mixing to regulate flame shape and NO_x.

The PG-DRB can be applied to new or retrofit situations. The system will usually include gas recirculation to the burner (PG) and to the windbox, with burners arranged in compartmented windboxes, and NO_x ports installed over the top burner row. B&W's first U.S. application of the PG-DRB was successfully commissioned in the summer of '88 at Hawaiian Electric's Kahe 6 unit. This retrofit upgrade includes burners, dual zone NO_x ports, GR system modifications, and controls. The NO_x emission guarantee was readily achieved, but opacity and particulate emissions were initially too high. B&W corrected this by application of T-Jet atomizers and tuning of the equipment, and thereby satisfied all guarantees. Los Angeles Department of Water & Power's Hayne Station Unit 4 will be retrofitted with PG-DRBs, compartmented windboxes, dual zone NO_x ports, GR system modifications, and control upgrades later this year.

XCL Oil/Gas Burner

Oil and gas capabilities were added to the XCL-PC Burner to satisfy a need by ENEL and Ansaldo Componenti, B&W's licensee in Italy (2). B&W contracted to supply XCL PC/Oil/Gas Burners for a 660 MW unit in southern Italy, contingent upon combustion test performance of a full-scale prototype burner (120 MKB). The multi-fuel XCL (Figure 14), patent pending, is designed with all the gas elements, coal nozzle, and oil atomizer--all the fuel elements--enclosed in a flame stabilizing ring in the burner throat. This permits "in-burner" fuel staging, in addition to controlled air/fuel mixing by the dual air zone arrangement. The large-scale combustion tests again confirmed XCL performance on coal, but most importantly revealed extremely favorable emission performance firing gas and oil. Figure 15 shows the results of XCL Burner design and HEMI fuel-staged gas spuds (patent pending) relative to a standard circular burner.

The XCL can reduce NO_x below 0.1 lb/MKB without use of gas recirculation or staging ports, with CO less than 50 ppm. Flame stability and turndown were exceptional--80:1. Results firing No. 6 oil indicated the XCL produced significantly lower NO_x than the circular or PG-DRB, over the wide range of conditions tested. Consequently B&W manufactured 56 multi-fuel XCL Burners which are scheduled to start up later this year at ENEL's Brindisi Sud Station, Unit 2.

On the merits of this excellent emission performance, B&W has deleted coal-firing aspects from the XCL and now also offers it as a gas/oil burner. The XCL O/G design (Figure 16) enables its use in an open windbox (compartmented windbox is unnecessary) as it makes use of the reliable S-Burner configuration. Air flow is controlled as a sliding air damper, measured by a pitot grid (to facilitate tuning during commissioning), and swirled by vanes in the dual air zones.

B&W completed combustion tests in the summer of '88 on the XCL-FM. The XCL-FM (Figure 17) is the designation for a package boiler version of the XCL Burner. The 50 MKB combustion tests at B&W's Alliance Research Center were performed in the package boiler on site, and confirmed excellent emission performance, with ambient air, firing No. 2 oil and natural gas. XCL-FM NO_x emissions were more than 50 percent lower than the circular or PG burner when firing gas, unstaged without GR. NO_x was less than 0.08 lb/MKB with CO less than 50 ppm. A commercial demonstration of the XCL-FM is in progress in one of the package boilers at Cal Tech.

In-Furnace NOx Reduction

In-Furnace NO_x Reduction (IFNR) provides the means to further reduce NO_x emissions during combustion. B&W has licensed rights to this reburning technology, which was developed by Babcock Hitachi and Tokyo Electric Power Company. Utility applications in Japan operate with NO_x emissions of 10-40 ppm on natural gas and 40-60 ppm with fuel oil. The IFNR system (Figure 18) consists of low NO_x burners operating below 1.0 stoichiometry in the main combustion zone, followed by low NO_x "planetary" burners operating at much lower stoichiometry to establish a reburning zone. Overfire air ports are situated beyond the planetary burners to provide sufficient residence time for NO_x reduction in the reburning zone and residence time to complete combustion before the gases exit the furnace. System configuration requirements and residence times are constraints which must be considered for new or retrofit applications.

POST-COMBUSTION NO_x CONTROL

A growing number of post-combustion systems are now in demonstration phases or commercially available to reduce NO_x emissions from boilers. These include ammonia injection systems situated just downstream of the furnace, in regions where flue gas temperatures are sufficiently high to avoid the need of catalysts for the reagent to reduce NO_x. Other systems have been demonstrated which use different reagents that favor somewhat lower temperatures found further downstream in the convection pass/boiler banks. DOE's Clean Coal program has spurred demonstration of systems downstream of the boiler which can simultaneously reduce emissions of NO_x and other pollutants. B&W's Puri-Fire^{TM}, the Hot Catalytic Scrubbing Baghouse (patent pending) reduces NO_x, SO_2, and particulate in one system (Figure 19). Pilot testing indicated 90 percent NO_x removal with up to 90 percent SO_2 capture and 99 percent plus particulate removal. B&W is negotiating with DOE (Clean Coal II) for a 5 MWe slip stream demonstration of this technology at Ohio Edison's Burger Station. Projected system start-up is for 1991.

Selective Catalytic Reduction (Figure 20) provides a proven means of reducing NO_x emissions to very low levels. B&W offers SCR systems (9) via our license with Babcock Hitachi. Economics and/or emission limits determine usage of SCR. Frequently it is used in combination with low NO_x combustion systems to achieve the best overall system. NO_x reduction performance is typically 80 percent, with installations operating as high as 95 percent removal when conditions dictate. Ammonia slippage, a concern with such systems, is nominally 10 ppm and can be reduced at the expense of an additional catalyst.

SUMMARY

Babcock & Wilcox's strategy is to develop and supply advanced combustion systems and post combustion systems to control NO_x emissions. These systems are intended for new boilers, and also for major categories of existing units which are expected to face NO_x restrictions in the future. The systems range from direct burner replacements to repowering with pressurized fluid beds. Application of low NO_x systems to new or existing equipment requires careful study and evaluation to ensure the intended performance objectives can be achieved compatibly with the balance of plant.

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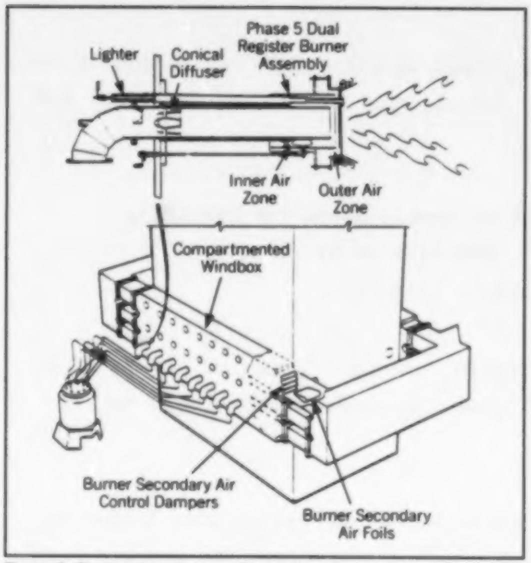
Phase 5 Dual Register Burner Assembly
Lighter
Conical Diffuser
Inner Air Zone
Outer Air Zone
Compartmented Windbox
Burner Secondary Air Control Dampers
Burner Secondary Air Foils

Figure 1 *Dual register burner (Phase V) and compartmented Windbox.*

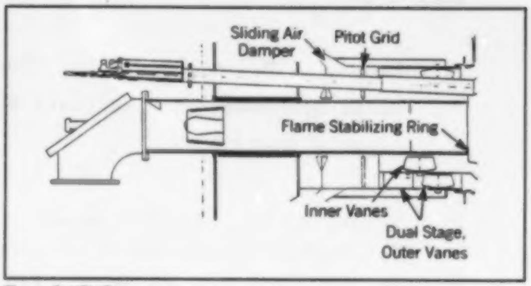
Sliding Air Damper
Pitot Grid
Flame Stabilizing Ring
Inner Vanes
Dual Stage, Outer Vanes

Figure 3 *XCL Burner.*

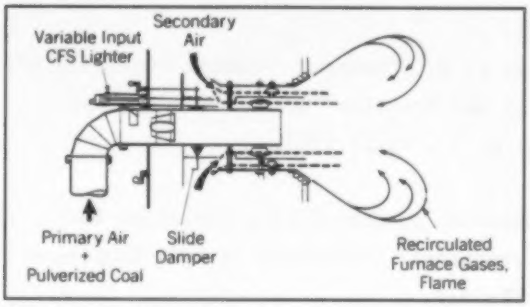
Variable Input CFS Lighter
Secondary Air
Primary Air + Pulverized Coal
Slide Damper
Recirculated Furnace Gases, Flame

Figure 2 *Enhanced ignition burner.*

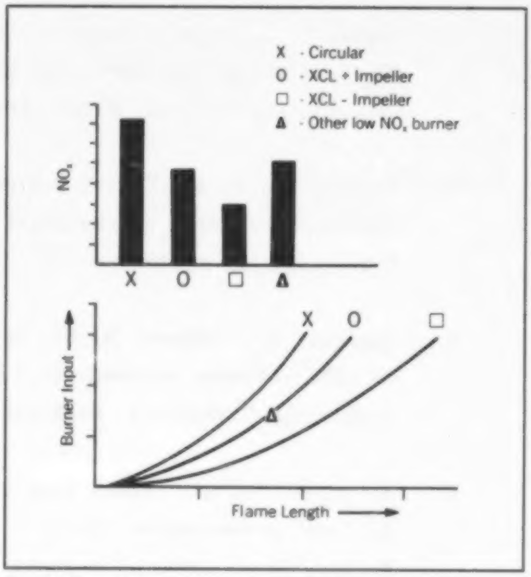

Figure 4 *Burner design influences on flame length and NO$_x$.*

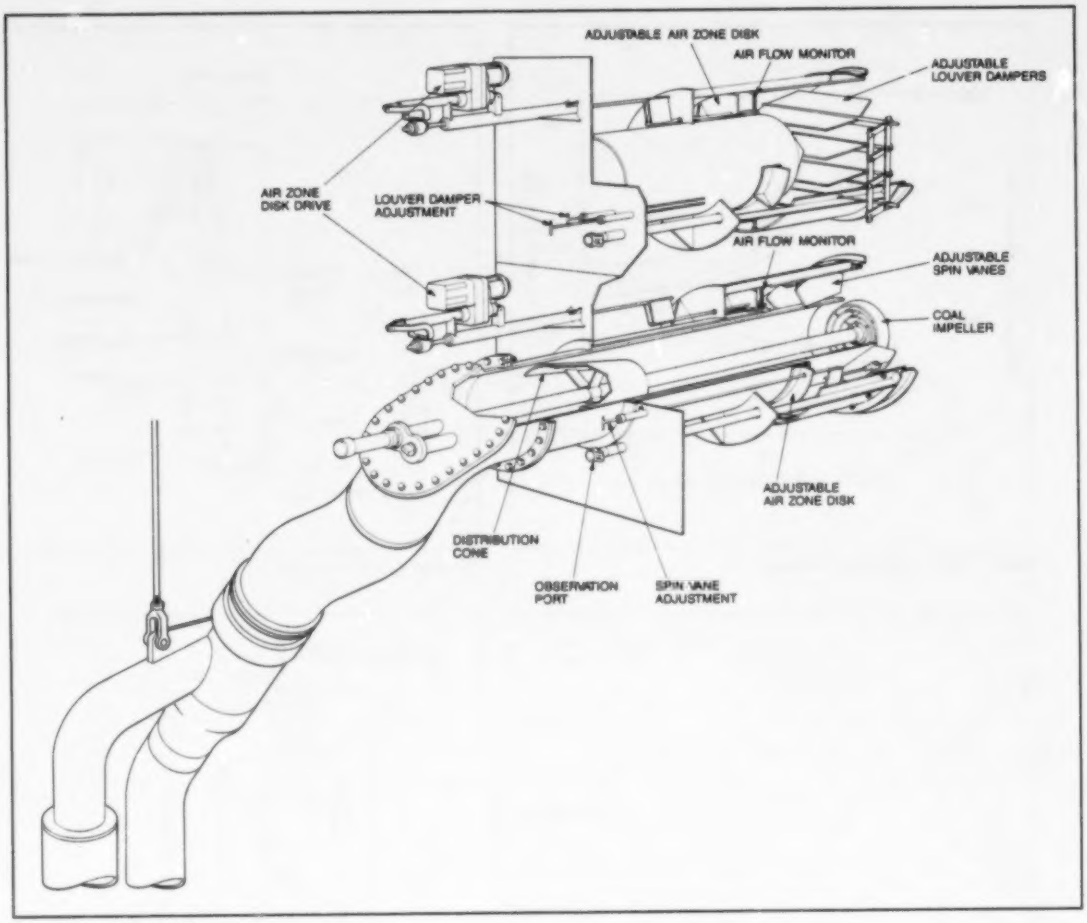
ADJUSTABLE AIR ZONE DISK
AIR FLOW MONITOR
ADJUSTABLE LOUVER DAMPERS
AIR ZONE DISK DRIVE
LOUVER DAMPER ADJUSTMENT
AIR FLOW MONITOR
ADJUSTABLE SPIN VANES
COAL IMPELLER
ADJUSTABLE AIR ZONE DISK
DISTRIBUTION CONE
OBSERVATION PORT
SPIN VANE ADJUSTMENT

Figure 5 *Low NO_x Cell Burner.*

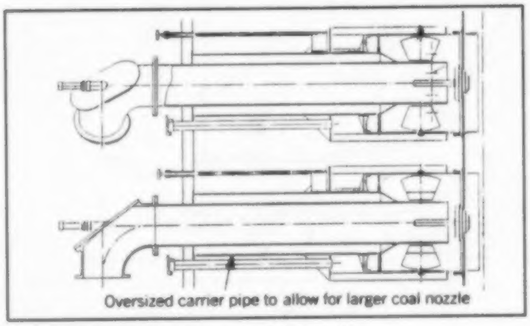
Oversized carrier pipe to allow for larger coal nozzle

Figure 6 *Convertible S Burner Low/NO_x cell.*

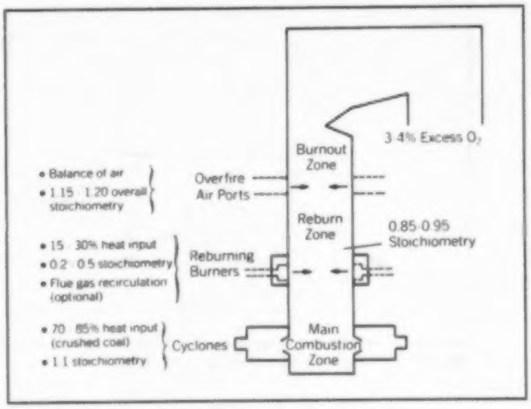
3-4% Excess O_2
Burnout Zone
• Balance of air
• 1.15 - 1.20 overall stoichiometry
Overfire Air Ports
Reburn Zone
0.85-0.95 Stoichiometry
• 15 - 30% heat input
• 0.2 - 0.5 stoichiometry
• Flue gas recirculation (optional)
Reburning Burners
• 70 - 85% heat input (crushed coal)
• 1.1 stoichiometry
Cyclones
Main Combustion Zone

Figure 7 *Reburning technology for cyclone-fired boiler.*

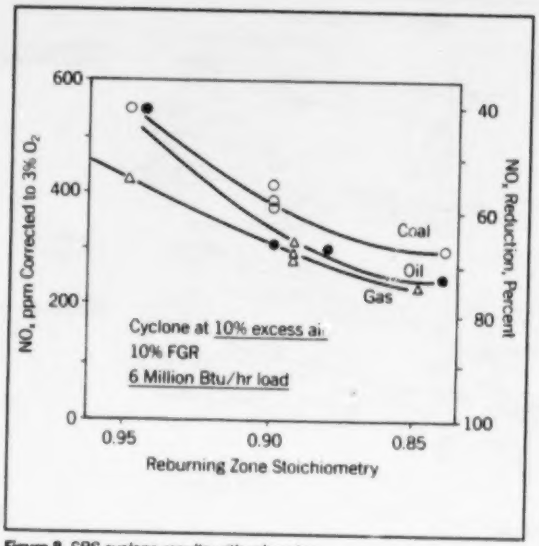

Figure 8 *SBS cyclone results with reburning.*

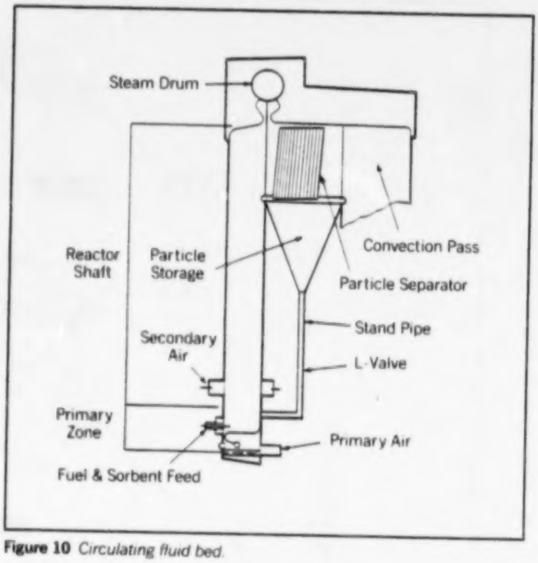
Steam Drum
Convection Pass
Reactor Shaft
Particle Storage
Particle Separator
Stand Pipe
Secondary Air
L-Valve
Primary Zone
Primary Air
Fuel & Sorbent Feed

Figure 10 *Circulating fluid bed.*

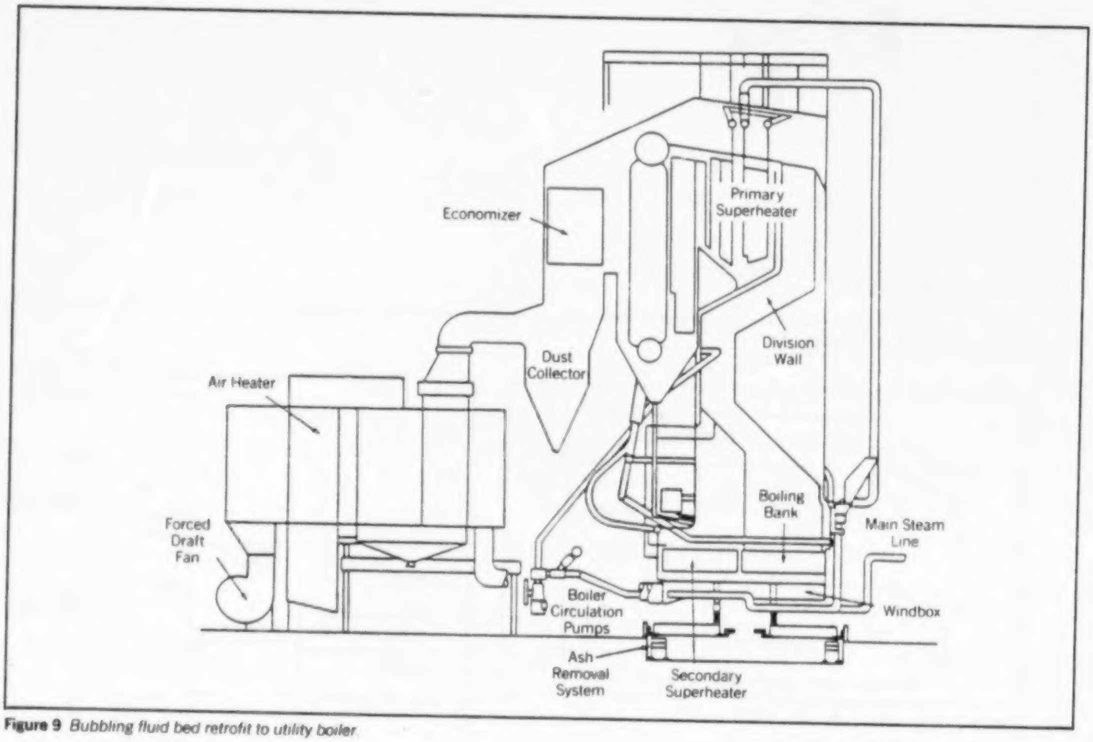
Economizer
Primary Superheater
Dust Collector
Division Wall
Air Heater
Forced Draft Fan
Boiling Bank
Main Steam Line
Boiler Circulation Pumps
Windbox
Ash Removal System
Secondary Superheater

Figure 9 *Bubbling fluid bed retrofit to utility boiler.*

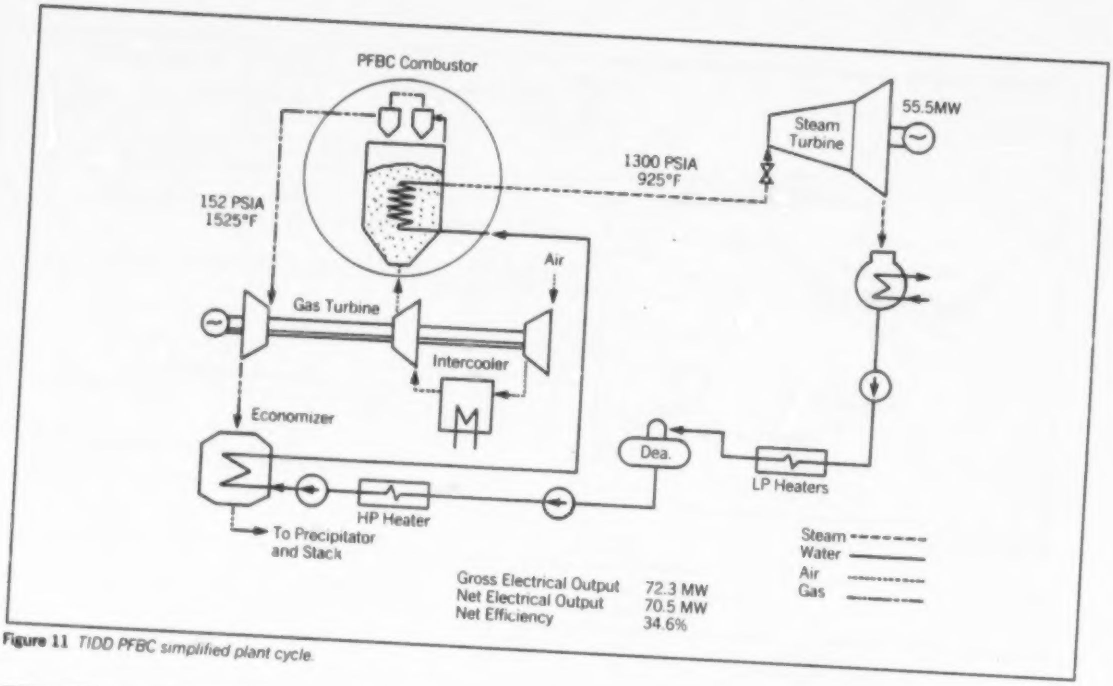
PFBC Combustor
55.5MW
Steam Turbine
1300 PSIA
925°F
152 PSIA
1525°F
Air
Gas Turbine
Intercooler
Economizer
Dea.
LP Heaters
HP Heater
To Precipitator and Stack
Steam
Water
Air
Gas
Gross Electrical Output 72.3 MW
Net Electrical Output 70.5 MW
Net Efficiency 34.6%

Figure 11 *TIDD PFBC simplified plant cycle.*

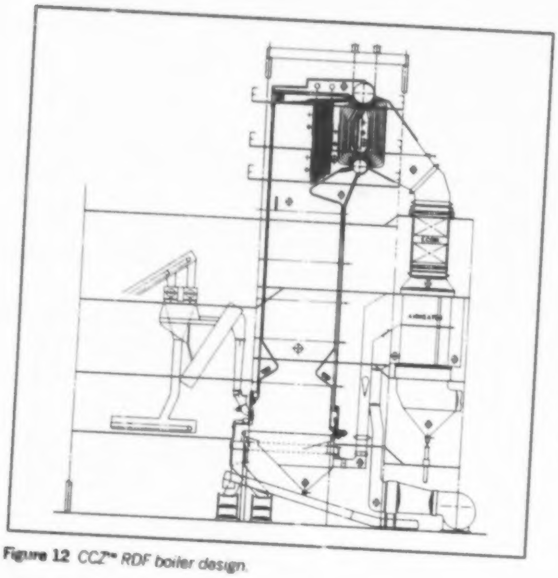

Figure 12 *CCZ™ RDF boiler design.*

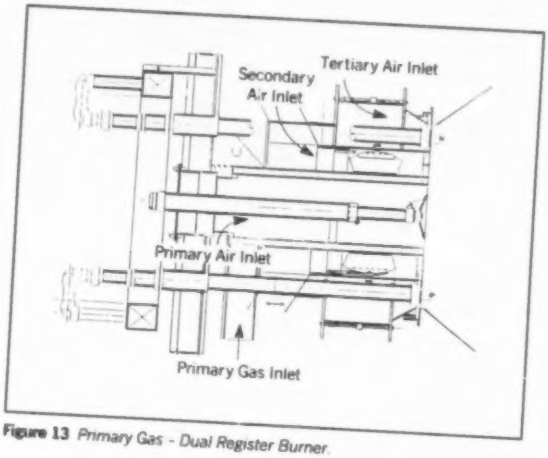
Tertiary Air Inlet
Secondary Air Inlet
Primary Air Inlet
Primary Gas Inlet

Figure 13 *Primary Gas - Dual Register Burner.*

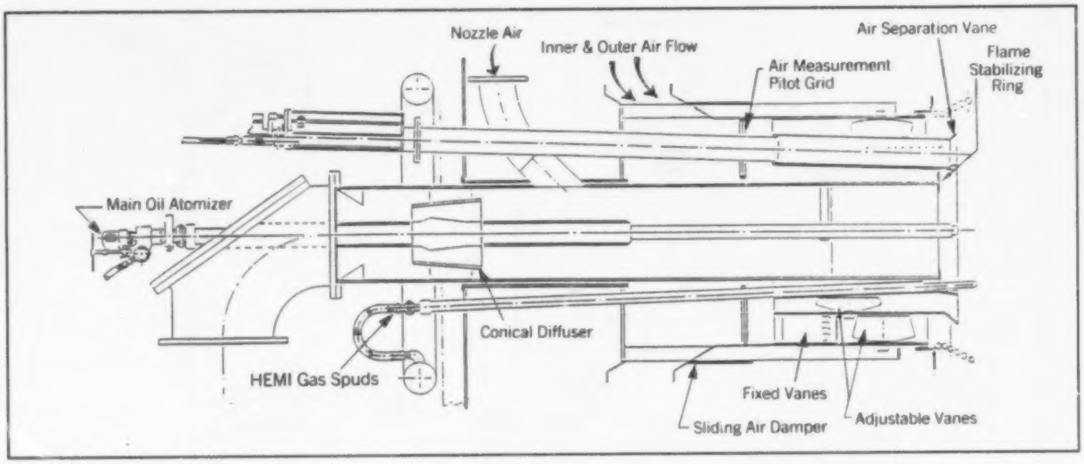
Nozzle Air
Inner & Outer Air Flow
Air Separation Vane
Air Measurement Pitot Grid
Flame Stabilizing Ring
Main Oil Atomizer
Conical Diffuser
HEMI Gas Spuds
Fixed Vanes
Sliding Air Damper
Adjustable Vanes

Figure 14 *Multi-Fuel XCL Burner.*

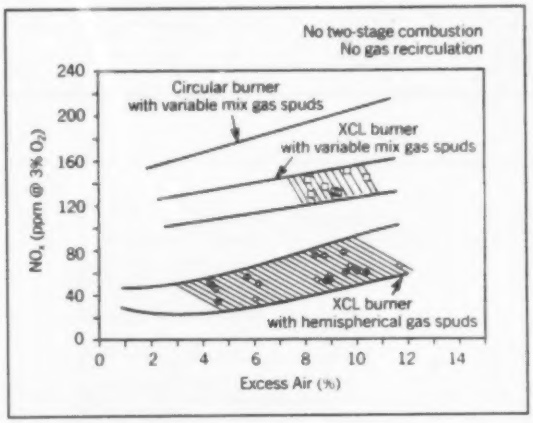

Figure 15 *XCL burner - gas firing.*

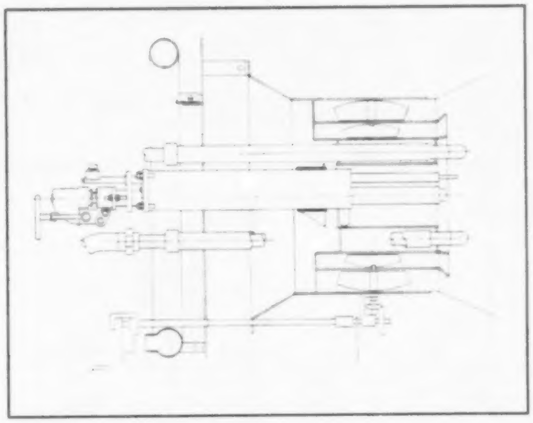

Figure 17 *XCL - FM Burner.*

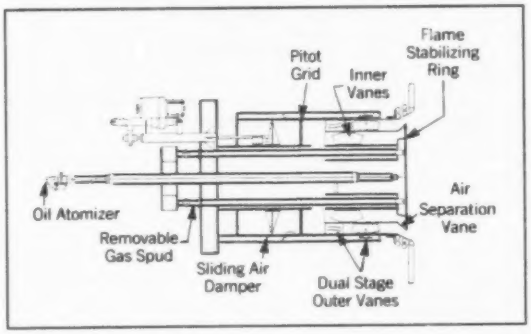
Pitot Grid
Inner Vanes
Flame Stabilizing Ring
Air Separation Vane
Oil Atomizer
Removable Gas Spud
Sliding Air Damper
Dual Stage Outer Vanes

Figure 16 *XCL oil/gas burner.*

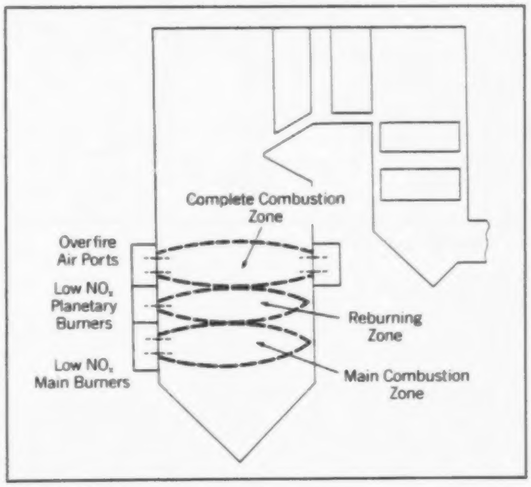
Complete Combustion Zone
Overfire Air Ports
Low NO_x Planetary Burners
Reburning Zone
Low NO_x Main Burners
Main Combustion Zone

Figure 18 *INFR system arrangement.*

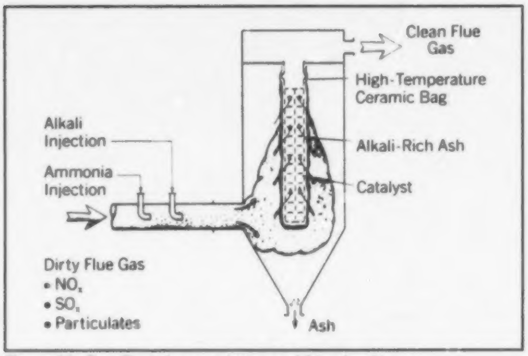
Clean Flue Gas
High-Temperature Ceramic Bag
Alkali Injection
Alkali-Rich Ash
Ammonia Injection
Catalyst
Dirty Flue Gas
• NO_x
• SO_x
• Particulates
Ash

Figure 19 *Puri-Fire™ hot catalytic scrubbing baghouse.*

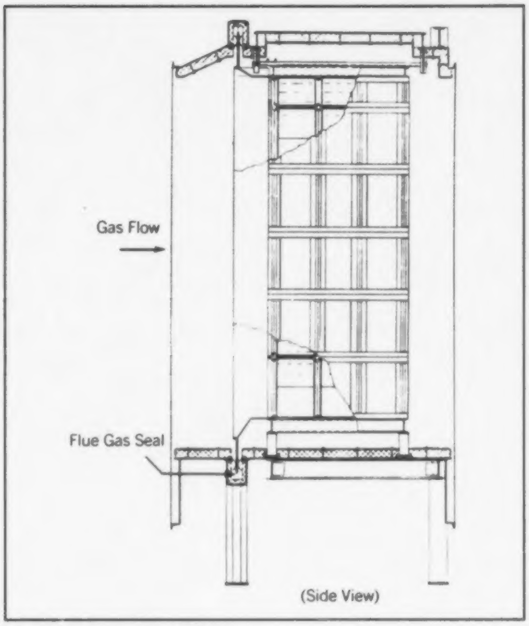
Gas Flow
Flue Gas Seal
(Side View)

Figure 20 *SCR reactor module.*

Table 1
Dual Register Burner Experience

Units in service	68	
Combined capacity (MW's)	37,050	
Smallest unit	65 MW (3 mills/6 burners)	
Largest units	1300 MW (14 mills/98 burners)	
DRB capacity range		
Minimum	1.5 MKB (Lab)/98 MKB (Field)	
Maximum	218 MKB (Field)	
Fuel Ranges - Coal	Minimum	Maximum
Moisture	3	35
Volatile Matter	19	40
Ash	4	35
Heating Value	4,900	13,900
- Fuel Oil		
- Natural Gas		

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1989 UPDATE ON NOx EMISSION CONTROL TECHNOLOGIES AT COMBUSTION ENGINEERING

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ABSTRACT

Combustion Engineering, Inc., by itself and in combination with Mitsubishi Heavy Industries, Ltd. under a licensing agreement, have engineered a complete range of NOx emission control technology for both new and retrofit applications. This paper presents a synopsis of each technology along with a brief overview of both the Kansas Power & Light - P.M. Firing system retrofit demonstration and our recent domestic SCR experience.

INTRODUCTION

Faced with potential impending acid rain legislation, the owners of domestic - fossil fuel fired - utility steam generators continue to seek the development and demonstration of retrofitable NOx emission control technology.

At Combustion Engineering work is continuously underway to both demonstrate our existing capabilities and develop new technology. As shown in previous joint NOx control symposia, Combustion Engineering has a diverse array of existing NOx reduction technologies available. These technologies have been developed by Combustion Engineering and Mitsubishi Heavy Industries, to address the broad range of possible reductions mandated by future legislation. A comparison of these various NOx control techniques for tangential coal fired utility boilers is shown in Figure 1.

Each of the systems presented in Figure 1 has a maximum percent NOx reduction which, in the opinion of CE, represents the practical technical limits for that technology. The degree of NOx control is compared to a base of 100% which would be typical of pre-New Source Performance Standard (NSPS) tangential fired units designed in the mid to late 1960s. For retrofit applications, the degree of NOx control may vary somewhat from the values presented depending upon physical and operational restraints encountered.

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This paper will present an updated synopsis of these NOx emission control technologies Combustion Engineering offers. In addition, this paper will focus upon the Kansas Power & Light - Pollution Minimum (P.M.) firing system retrofit demonstration and our recent Selective Catalytic Reduction (SCR) domestic experience.

TRADITIONAL TANGENTIAL FIRING SYSTEM

Virtually all of the current low NOx burner systems are designed to reduce the availability of oxygen at some point in the history of the fuel within the furnace. In the early 1970s, designers of fuel burning equipment pursued the reduction of high temperature zones within the furnace in an attempt to control the THERMAL portion of total NOx - e.g., simply stated, NOx = Thermal NOx + Fuel NOx. Most of the recent fundamental research on the kinetics of fuel-bound nitrogen focus on the very early devolatilization process, an initial period of events in the combustion process during which very large quantities of fuel nitrogen are released. The potential for nitrogen conversion to NOx is high at this time. Overfire air (OFA) plays a minor role in controlling NOx formed early in the combustion process, because the 15% to 20% of the total air that goes to the OFA is a very small part of the O_2 available to the volatile matter being burned and fuel nitrogen being released. Thus, to control the all-important fuel nitrogen conversion, large quantities of air must be withheld from the fuel for the duration of the devolatilization and small char particle combustion process. By withholding a sufficient quantity of air from the combustion of volatile matter, the system is simultaneously deprived of a sufficient quantity of O_2 to oxidize nitrogen to NO. The ideal system of igniting and burning pulverized coal would be to pre-mix a minimum amount of air with the pulverized coal, promote strong ignition, and then mix the balance of the required air at later successive stages during the combustion process.

CE's traditional tangential firing system mimics this ideal arrangement, as shown in Figure 2. From each corner windbox, separate vertically stacked, nozzles emit distinct levels of fuel and air, promoting strong ignition near each corner. The bulk mixing process induced by the rotating fireball pattern shown in Figure 3, ensures the complete mixing of the fuel and air.

The four distinct, controlled air zones, contained within every CE tangential windbox are listed below:

1. Primary Air is used to dry and transport the coal, and is injected into the furnace through the coal nozzle assembly.

   All remaining airflow is considered secondary air, and is classified as follows:

2. Fuel Air is that portion of the windbox air (secondary air) that is injected into the furnace annularly to the primary air.

3. Auxiliary Air is the balance of the air required for combustion that was not used by the primary or fuel air or overfire air. Most of the auxiliary air is injected into the furnace through separate compartments located in between each fuel compartment.

4. Overfire Air (OFA) is the remaining auxiliary air that is introduced to the furnace through OFA ports located at the top of (or above and separate from) the main windbox.

LOW NOx CONCENTRIC FIRING SYSTEM

In 1980, CE developed a firing system concept referred to as the Low NOx Concentric Firing System (LNCFS). By design, the LNCFS proportions the secondary air flow through the windbox so as to effect a decrease in the amount of fuel air while increasing the amount of auxiliary air. In addition, the auxiliary air is directed away from the fuel towards the furnace wall in order to reduce the entrainment of auxiliary air by the expanding primary air/coal jet (Figure 4). This diversion effectively provides more favorable conditions for low NOx emissions during the initial combustion process than provided by only OFA equipped firing systems. While both OFA and LNCFS can be referred to as "staging" techniques, OFA is a type of "vertical staging" for controlling NOx emissions, and LNCFS can be thought of as a "horizontal staging" technique - unique to tangential firing.

As a practical matter, LNCFS affects the "early stoichiometry" for a very limited amount of time. The cross mixing patterns inherent in tangential firing are massive and separation of both streams are quickly lost as they penetrate the furnace. Thus LNCFS requires the use of "flame attachment" nozzle tips to accelerate the devolatilization process. Therefore to retrofit LNCFS, all the air and fuel nozzle tips require replacement (Figure 5). No structural windbox or pressure part changes are normally required, and after OFA, LNCFS is the next least costly modification available to reduce NOx. For a unit without provisions for OFA, LNCFS can be economically installed, in view of periodic replacement of fuel nozzle tips due to erosive wear.

LNCFS Demonstrations

An extensive field demonstration of the LNCFS concept was conducted at Utah Power & Light, Hunter #2, under EPA contract. Results from these tests were presented in previous symposia (Reference 1 and 2) and in the EPA final project report (Reference 3). More recently, CE's licensee in Great Britain, NEI International Combustion, Ltd. has completed the demonstration of an LNCFS system at the Central Electric Generating Board (CEGB) Fiddlers Ferry No. 1 Power Station. Results of NEI's demonstration were presented at the 1987 Joint NOx Symposium (Reference 4).

Briefly, both demonstrations yielded approximately a 20% NOx emission reduction beyond the standard tangential firing system equipped with OFA. The tests show the reductions due to LNCFS are additional to those already achieved with OFA. This evidence supports the theory LNCFS and OFA retard the conversion of fuel bound nitrogen at different times during the combustion process.

CE/MHI PM BURNER

The coal fired PM burner is part of a family of ultra low NOx burners capable of firing coal, oil, and gas. The PM system was developed by Mitsubishi Heavy Industries (MHI) and has been licensed to Combustion Engineering for application in North America. In addition to using a bulk staging combustion technique (OFA), the PM burner emits low NOx emissions by reducing the local stoichiometry (available O_2) around the coal particle early in the combustion process. The extensive laboratory work behind the PM burner has gone further to identify a relationship between NOx and the pulverized coal/air transport ratio. As seen in Figure 6, tests show typical transport air/fuel ratios (NOx value at Co) are not conducive to low NOx. In fact, air to coal ratios that are either higher or lower than typically found in modern pulverized coal units would result in lower NOx. With the benefit of this information, the PM burner is quite straightforward. Since the primary air to fuel ratio from the pulverizer cannot as a practical matter be changed, the MHI burner separates each fuel line in two streams prior to the windbox (see Figure 7). In theory, neither the fuel rich (CONC) nor the air rich (WEAK) injection nozzle has a fuel nitrogen conversion ratio as high as a single nozzle with the air and fuel combined (see Figure 6). In practice, this theory has been supported by both large scale laboratory prototype testing as well as field testing in a large industrial boiler in Japan.

PM Burner Application Study

Under EPRI sponsorship, the coal fired PM prototype was thoroughly evaluated under a two phase program. This program consisted of PM burner laboratory combustion testing with U.S. coals, followed by an engineering feasibility and cost analysis for U.S. applications. The results of this application study were present in the 1987 Joint NOx symposium and are available from EPRI under Reference 5.

Briefly, this evaluation indicated NOx emissions in the range of 0.20 - 0.25 lb/10^6 Btu are both technically and economically feasible.

PM Burner Demonstration

Following up this economic feasibility and technical evaluation analysis, the next logical step was a full scale utility demonstration of this technology. This phase was desired since although the system had been demonstrated on new units, in Japan, the system had never been retrofit.

To serve this purpose, EPRI issued a request for potential PM firing system candidates. Their project objective was to demonstrate the maximum achievable NOx reduction with minimal impact on plant performance. After reviewing several host site candidates, the Kansas Power and Light Gas Service - Lawrence 5 boiler was selected. In late 1986, KP&L contracted CE to design, fabricate and install the PM firing system during their upcoming spring 1987 scheduled outage.

This plant was designed by Combustion Engineering in the mid-1960s for a 400 MW generating capacity, and went into service in 1971. The steam generator utilizes controlled circulation radiant reheat technology, and at the maximum continuous rating produces 2,805,000 lb/hr of 1005°F superheated primary steam with a reheat steam flow of 2,450,000 lb/hr at 1005°F. The boiler is 50'-8" wide by 40'-2-1/8" deep and is equipped with fusion welded waterwalls, a multi-stage superheater with panels, platens and a finishing pendant, a multi-stage reheater with a radiant wall and pendant, and economizer (see Table 1).

The existing firing system was designed for full load operation with either natural gas, #6 oil or Midwestern Bituminous pulverized coal. Gas and oil can be fired through 4 elevations of corner located tangential fuel admission assemblies, and pulverized coal can be fired from the 4 corners through 5 elevations of coal nozzle assemblies. These coal elevations are supplied fuel from 5 CE 743 RS bowl mills. Ignition of the fuel is provided through 2x10^6Btu/hr natural gas fired side mounted ignitors. Since this unit was designed prior to the 1971 NSPS, the existing windboxes were not equipped with OFA.

The new equipment CE supplied as part of the PM firing system included all new PM burner style coal nozzles including PM fuel piping separators, one new elevation of gas ignitors, a new secondary air damper control system, and replacing a portion of the existing pulverized coal fuel piping. These 4 new windboxes each capable of firing gas, oil or pulverized coal also provided an integral close coupled OFA arrangement and a separated OFA system arrangement. This separated OFA system included two individually controlled compartments, with each nozzle providing both vertical tilt and horizontal yaw adjustment. As designed, the main windbox and integral OFA arrangement tilt in unison for reheat steam temperature control and the separated OFA arrangement is independently set for NOx emission control. A comparison of the taller retrofit PM windbox with the existing windbox is provided in Figure 8.

A scheduled 8 week outage, starting at the end of April 1987, was set aside for installing this equipment. This project schedule provided a significant coordination challenge since only 5 months were available for designing and detailing the equipment through manufacturing and shipping.

With the firing system design well underway, EPRI contracted the Fossil Energy Research Corporation (FERCO) to conduct a series of emission tests. Their objective was to characterize the boiler emissions both prior to and after the PM firing system retrofit. In addition, the intent was to establish the baseline test conditions to be used for comparison with future post modification, and long term tests. At about the same time, EPRI contracted Combustion Engineering to establish the boiler overall performance during both the baseline and post retrofit test series.

Following these baseline tests, the scheduled outage began April 26, 1987. The actual installation went fairly smoothly, with temporary support steel installed in the furnace bottom through a hole made in the boiler north wall. It was through this hole that the existing windboxes were slid out after a portion of the waterwall panel was cut loose around the entire windbox area. Afterwards, the new windboxes were slid through this opening and lifted up into place (see Figures 9, 10). Following the waterwall tube fit-up and welding process, the temporary support steel was removed and the north wall opening was closed. Late in this outage, a turbine related problem was discovered, forcing a 3 week outage extension. Although this extension relieved some of the shift time required for the PM firing system retrofit, the original 8 week schedule could have been maintained.

The unit was restarted July 16, 1987 and the subsequent start up testing did not uncover any boiler problems. Following a series of extensive diagnostic testing and a scheduled fall outage, the unit characterization matrix tests were carried out. Figures 11-15 summarize these post modification tests.

The most important program result was the overall boiler performance was only minimally changed. Comparing the baseline steam side absorption with the normal PM firing system operation (Figure 11) the economizer sectional absorptions were essentially identical, and the PM firing waterwall sectional absorption was slightly higher than the baseline absorption. This is further emphasized by Figure 12 where the normal PM firing system operation typically yielded a furnace exit gas temperature approximately 40-50°F lower than the baseline firing system. For comparison, a 120°F change in FOT was experienced with the baseline firing system between a clean and dirty furnace.

The NOx emission results, see Figure 13, on the other hand, showed a 50% reduction at a nominal 320 MW boiler load between the "tuned" baseline firing system and PM firing system. The "Tuned" baseline performance represents the "best" normal operation obtained during the baseline characterization matrix testing, as opposed to the "as found" emissions represented by the discrete data points. As shown, the PM data represents normal, combined OFA operation of the PM firing system with both the close coupled and separated OFA compartment in service providing approximately 25% total OFA. At lower loads, the preliminary PM firing system results also look encouraging, but at this time, the official results are not available.

The PM firing system dependence on OFA flow is shown in Figure 14. Based upon the Lawrence tests, approximately 30% of the NOx reduction can be attributed to the PM firing system, while approximately 70% of the reduction is attributed to the OFA air system.

For long term operation, it appears the Lawrence 5 boiler efficiency will be between 0.2% and 0.25% lower with the PM firing system. This efficiency penalty is due to increased dry gas losses associated with an approximately 0.5% increase in boiler O_2 required for the 50% NOx reduction/25% OFA operation (see Figure 15).

CE/MHI MACT

No matter how closely the combustion process is controlled, the prerequisites for completing the combustion process (temperature, time, and excess oxygen) will be sufficient to generate at least some NOx. State-of-the-art firing systems such as the PM burner can do an excellent job of burning pulverized coal as well as liquid and gaseous fuels, but there is always a minimal value below which further reduction in NOx is impractical. Thus, for very low NOx requirements, techniques have been developed to actually destroy NOx already formed by the combustion process. One such technique has been developed by MHI and subsequently licensed to CE. This system is called MACT which is an abbreviation for Mitsubishi Advanced Combustion Technology.

MACT is designed to take advantage of the high temperature kinetic characteristics of the nitrogen oxide molecule. Nitrogen oxide is relatively unstable at the elevated temperatures commonly found in the mid furnace sections of most modern pulverized coal fired boilers. Above 1200°C, the NO molecule can be "destroyed" by reacting with certain radicals at high temperatures. The high temperature chemistry is not in itself new, but what is unique to the MHI process reactions can be represented as follows:

$$C_nH_m + O_2 \longrightarrow C_n'H_m'^{*} + CO + H_2O$$
$$NO + C_n'H_m'^{*} \longrightarrow C_n''H_m'' + N_2 + H_2O + CO$$
$$NO + C_n'H_m'^{*} \longrightarrow C_n''H_m'' + NH_i + H_2O + CO$$

The asterisks (*) denote a radical at the initial stage of chemical reaction and NH_i represents any nitrogen compound.

Conceptually, the MACT process can be seen in Figure 16. Compared to conventional firing systems, MACT diverts a small percentage of fuel from the main burner combustion zone and injects the fuel through UFI (Upper Fuel Injection) ports with an inert propellant, usually flue gas. The fuel injected into the "De-Noxing Zone" has insufficient oxygen to burn. Upon reaching sufficient temperature, the fuel generates, for a brief period of time, high temperature radicals which have such a high affinity for oxygen that they literally strip the oxygen from the NO molecule. This high temperature thermal decomposition of NO is called the "De-Noxing" (DN) process.

Since the fuel injected into the mid-furnace area in the DN process must be burned to completion to salvage the heating value of the fuel and to prevent hydrocarbon emission, the balance of the required combustion air is injected at the "AA elevation (Figure 17). The "AA" process is the straightforward oxidation of the products of incomplete combustion leaving the DN process.

AA process:

$$C_n''H_m'' + O_2 \longrightarrow H_2O + CO_2$$
$$CO + O_2 \longrightarrow CO_2$$
$$NH_i + O_2 \longrightarrow N_2 + H_2O$$
$$NH_i + O_2 \longrightarrow NO + H_2O$$

It is interesting to note the last reaction shows the formation of NO. In both theory and practice, the MACT system does a very effective job of destroying most of the NO in the DN process but regenerates some of the NO in the "AA" process. The amount of NOx that is regenerated in the "AA" process is dependent on the fuel nitrogen content and reactivity of the reburn fuel. Natural gas, or low nitrogen oil may be used as the deNOx or reburn fuel. This is significant because it means that MACT can be utilized in conjunction with conventional firing systems (tangential and wall fired) as well as with low NOx burner systems such as the PM burner to produce NOx concentrations on new boilers as low as 70 ppm to 115 ppm (vol. corrected to 3% O_2) firing pulverized coal.

MACT Applications

MHI has had an oil fired PM/MACT combination in commercial service since January of 1981 in Japan. A 600 MW unit has been in operation since September of 1983 utilizing fuel oil as the "MACT fuel" and oil/pulverized coal in the main windbox - See Reference 6.

POST COMBUSTION CONTROL OF NOx

The NOx reduction capabilities of in-furnace combustion modifications are considerable. However, there are minimum levels at which further NOx reduction by these methods becomes impractical. With the use of dry catalytic tail end systems, reductions of up to 90% in NOx levels can be achieved.

Due to the stringent NOx regulations in Japan, Mitsubishi Heavy Industries, Ltd. (MHI) began developing a dry NOx removal process for its steam generating units in the early seventies. This was a developmental process in which the catalytic systems were first applied to natural gas fired units, then to low and high-sulfur oil fired units and finally to coal fired boilers. To complement existing CE NOx reduction technology, a license agreement was signed with MHI in April 1980, making the catalytic and low NOx burner technology and products available to CE for steam generators in the United States and Canada.

SCR DOMESTIC INSTALLATIONS

During the past two years, CE has been involved with the design and installation of several selective catalytic reduction systems (see Table 2). These projects have been primarily for gas fired cogeneration heat recovery units and industrial boilers in the California area. The application of SCR technology was required for each of these projects in order to meet stringent local NOx emission standards.

A CE shop assembled boiler and SCR system installed at Chevron's El Segundo Refinery began operation in February 1988. The SCR reactor at this site is located adjacent to the steam generator. The flue gas from the boiler flows vertically downward through the SCR reactor chamber. A single layer of catalyst modules is installed in the SCR unit to treat the incoming flue gas. Additional space has been provided at the boiler exit to accommodate the future installation of a CO catalyst (see Figure 18).

Upstream of the SCR reactor chamber, in a horizontal duct run, the ammonia injection pipes, nozzles and mixing grid are installed. A diluted mixture of ammonia gas in air is dispersed into the flue gas stream through orificed openings in the ammonia injection nozzles. Downstream of the ammonia air injection point is a fixed gridwork of carbon steel pipes used to achieve a uniform distribution of ammonia in the flue gas before it enters the SCR reactor chamber. The gas then exits the SCR chamber, flows through a separately encased economizer section and finally discharges up the stack.

The steam generator at the Chevron facility is used primarily as a source of back up power and process steam to an adjacent gas turbine cogeneration plant. The unit is designed to fire natural gas, refinery gas and future no. 2 oil. Refinery gas has been the primary fuel since unit start up. The SCR system has been successfully operating across the full load range of the boiler achieving greater than 90% NOx removal efficiency. Ammonia slip levels (unreacted ammonia) have been negligible.

The first CE installation of a SCR system into a heat recovery boiler is expected to begin operation during the first quarter of 1989 at Harbor Cogenerating Plant in Wilmington, California. This unit will provide power from a GE Frame 7 gas turbine (approximately 75 MW) as well as process steam (465,000lb/hr) from a waste heat boiler for enhanced oil recovery.

The SCR chamber is located downstream of the first module of heating surface where suitable SCR operating temperatures are available. The ammonia injection grid has been designed as an integral part of the first pressure part module. Upstream of the waste heat boiler is a CO catalyst designed for 90% removal efficiency.

The SCR system at the Harbor Cogeneration Plant treats the flue gas from a natural gas and refinery gas fired turbine. The design NOx removal efficiency is approximately 83%. Unreacted ammonia levels are designed for less than 10 ppmvd at 15% O_2. A three (3) year catalyst life guarantee is provided for the honeycomb ceramic based catalyst.

The SCR units at Chevron's Richmond Refinery have been operating since July 1984. These units are located at the exit of three process heaters. The SCR systems are designed for 65% NOx removal efficiency. At present, the units are still performing within design limits and no new replacement catalysts have been required.

SCR technology in the U.S. has been primarily applied to liquid and gaseous fuels for industrial boilers and gas turbine cogeneration projects. These SCR applications were required in order to meet strict local emission requirements. So far, whenever NOx emission requirements have gone below levels practical for combustion modifications, SCR systems have proven to be a viable option.

CONCLUSION

The technology needed to comply with anticipated future NOx emission regulations is already commercially available. Furnace combustion modifications, post combustion catalytic systems or a combination of both methods may be considered for new or existing units depending upon the level of NOx emissions to be achieved. As shown in Figure 19, the relative costs of reducing NOx can vary significantly. Each method must be carefully analyzed to determine the most appropriate and cost effective technique for the desired NOx emission level.

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1. Lewis, R.D., et al, "Low NOx Coal Firing System Demonstration Results on a Tangentially Fired Boiler," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.

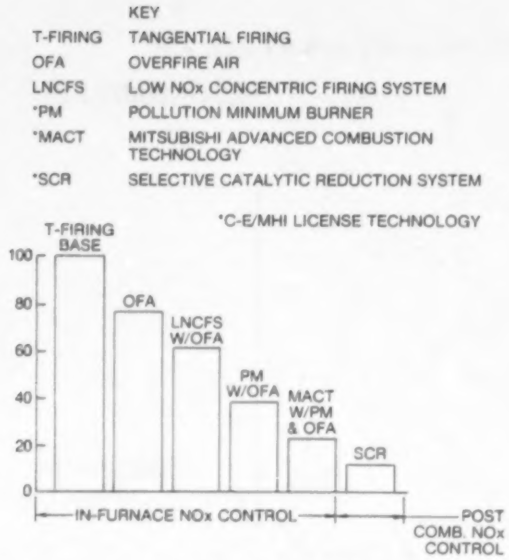
2. Kokkinos, A. and Lewis, R.D., "Field Evaluation of a Low NOx Firing System for Tangentially Coal-Fired Utility Boilers," Final Project Report, July 1985, EPA Report No. 600/7-85-018.

3. Kokkinos, A., et al, "Low NOx Firing System for Tangentially Coal-Fired Utility Boilers - Preliminary Testing," proceeding of the 1982 Joint Symposium on Stationary Combustion NOx Control, Vol. 1, July 1983, EPRI, Palo Alto, California.

4. Sargeant, M., et al, "Reductions in NOx Emissions from a 500 MW Corner-Fired Boiler," presented at the 1987 Joint Symposium on Stationary Combustion NOx Control.

5. Kokkinos, A. and Donais, R. E., "Evaluation of the PM Burner: A Low-NOx Pulverized-Coal-Firing system for Tangentially Fired Utility Boilers", Final Report, February 1987, EPRI Research Projects 1836-1,-2.

6. Murakani, N., et al, "Application of the "MACT" In-Furnace NOx Removal Process Coupled with a Low-NOx SGR Burner," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.



100% BASE NOx LEVELS ARE EQUIVALENT TO PRE-1970 BOILER DESIGNS (TYPICAL NOx RANGE 0.5 - 0.7 LBS/10^6 BTU)

Figure 1. A Comparision of Various NOx Reduction Techniques For Tangential Coal Fired Boilers

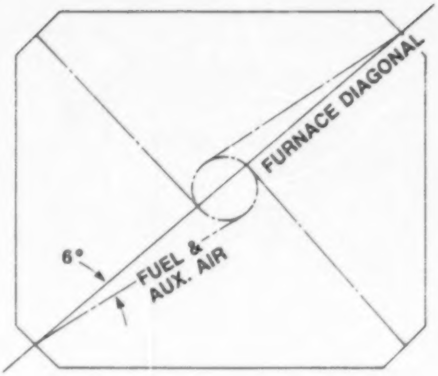


Figure 2. Typical Plan View of Fuel And Auxiliary Air Streams in Tangential Firing System

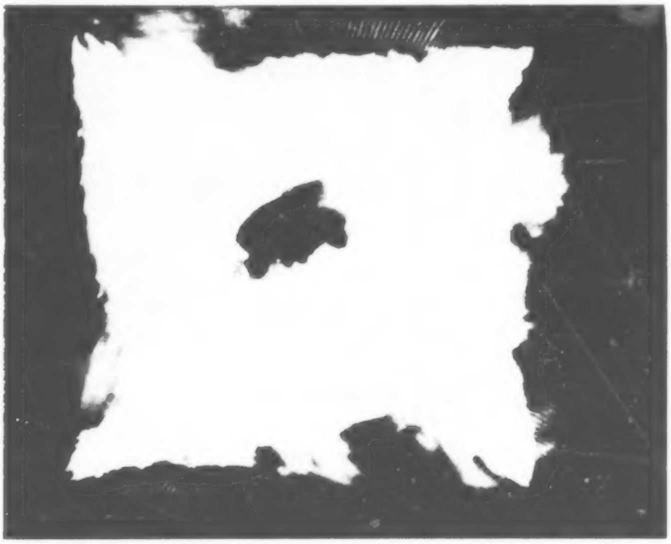


Figure 3. Plan View of Tangentially Fired Steam Generator Flame Pattern

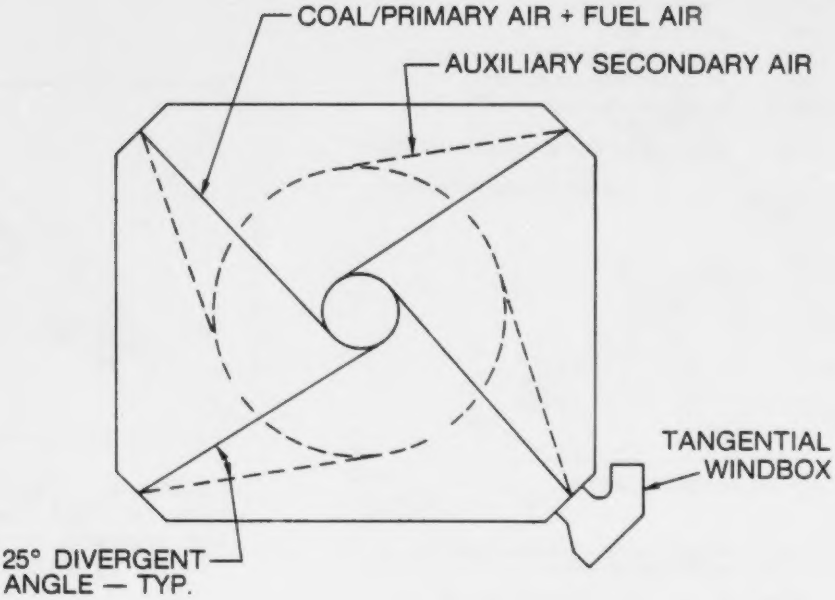

COAL/PRIMARY AIR + FUEL AIR
AUXILIARY SECONDARY AIR
TANGENTIAL WINDBOX
25° DIVERGENT ANGLE — TYP.

Figure 4. Furnace Plan View - LNCFS

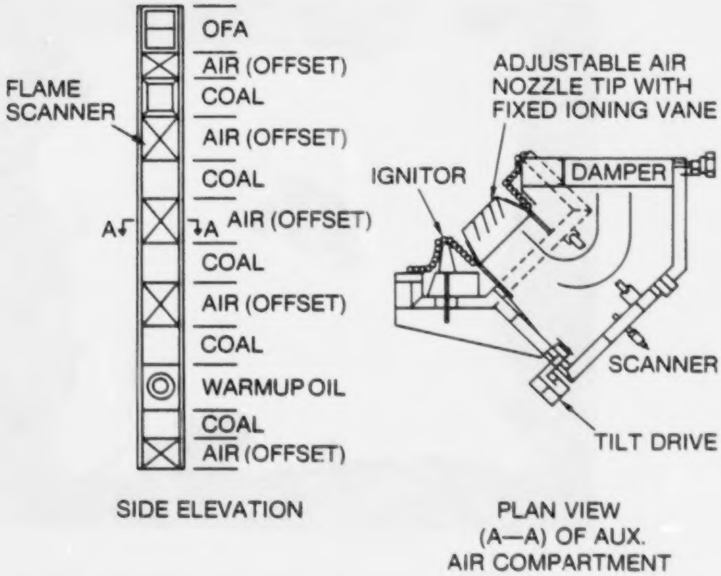

OFA
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
WARMUP OIL
COAL
AIR (OFFSET)
FLAME SCANNER
A
A
SIDE ELEVATION
ADJUSTABLE AIR NOZZLE TIP WITH FIXED IONING VANE
IGNITOR
DAMPER
SCANNER
TILT DRIVE
PLAN VIEW (A—A) OF AUX. AIR COMPARTMENT

Figure 5. Air Nozzle Tip Design - LNCFS

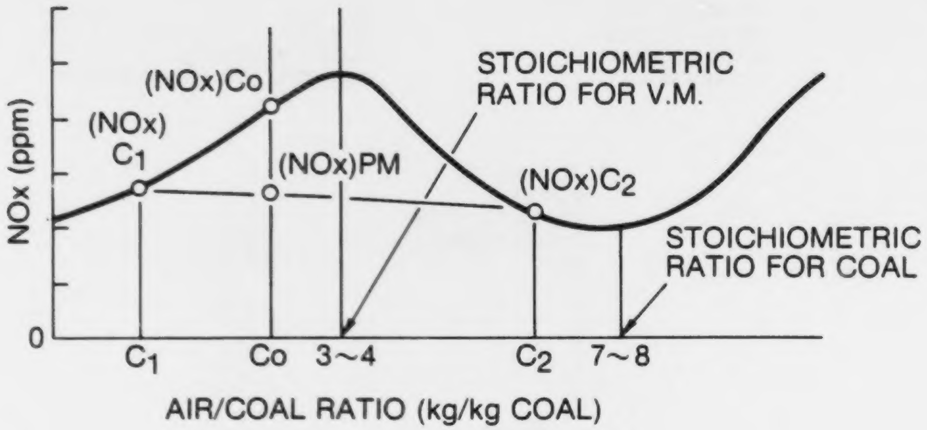


Figure 6. Concept of Pulverized Coal Fired Low-NOx C-E/MHI PM Burner

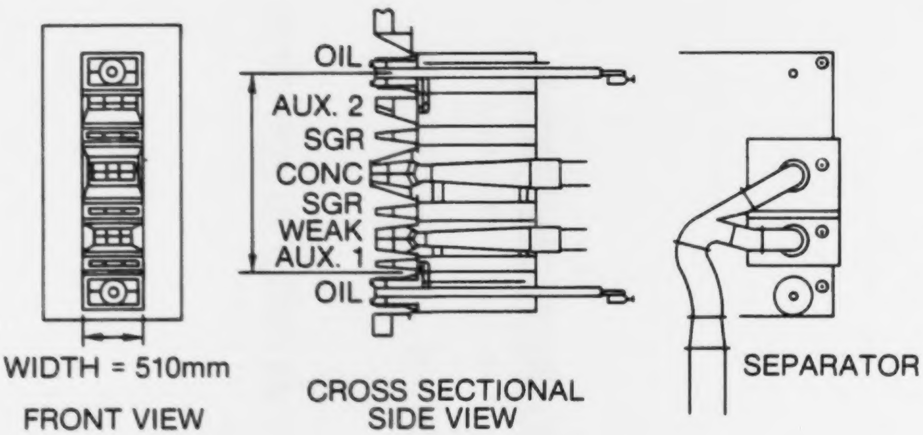

OIL
AUX. 2
SGR
CONC
SGR
WEAK
AUX. 1
OIL
WIDTH = 510mm
FRONT VIEW
CROSS SECTIONAL SIDE VIEW
SEPARATOR

Figure 7. Structure of Coal Fired Low-NOx C-E/MHI PM Burner

GENERATOR RATING	400 MWe
MAXIMUM STEAM FLOW	2,805,000 lb/hr
SUPERHEAT STEAM TEMPERATURE/PRESSURE	1005ºF/2620 psig
FURNACE WIDTH	50' - 8"
FURNACE DEPTH	40' 2-1/8"
FIRING SYSTEM	TILTING TANGENTIAL
PULVERIZERS	FIVE 743RS (WITH EXHAUSTERS)

FUEL ANALYSIS:	
MOISTURE	10.5 %
VOLATILE MATTER	38.0 %
FIXED CARBON	42.9 %
ASH	8.6 %
H	4.50%
C	61.91%
S	0.47%
N	1.27%
O	12.75%
ASH	8.60%
MOISTURE	10.50%
HHV	10,884 Btu/lb

Table 1. Kansas Power And Light - Lawrence 5 Boiler Design Parameters and Actual Coal Analysis

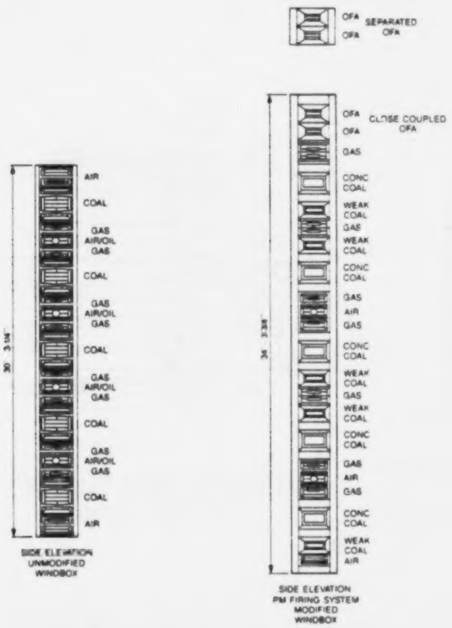

OFA
OFA
SEPARATED OFA
OFA
OFA
CLOSE COUPLED OFA
GAS
CONC COAL
WEAK COAL
GAS
WEAK COAL
CONC COAL
GAS
AIR
GAS
CONC COAL
WEAK COAL
GAS
WEAK COAL
CONC COAL
GAS
AIR
GAS
CONC COAL
WEAK COAL
AIR
34' 3 3/8"
SIDE ELEVATION PM FIRING SYSTEM MODIFIED WINDBOX
AIR
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
GAS
AIR/OIL
GAS
COAL
AIR
30' 3 1/4"
SIDE ELEVATION UNMODIFIED WINDBOX

Figure 8. Kansas Power And Light - Lawrence 5 Comparison of Baseline And PM Retrofit Windboxes

Reproduced from
best available copy.

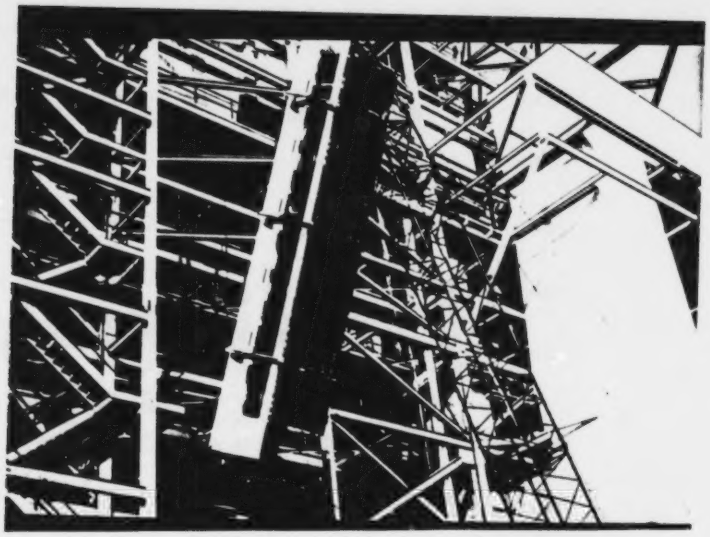


Figure 9. PM Retrofit Windbox Construction
Just Prior To Being Slid Into The Boiler

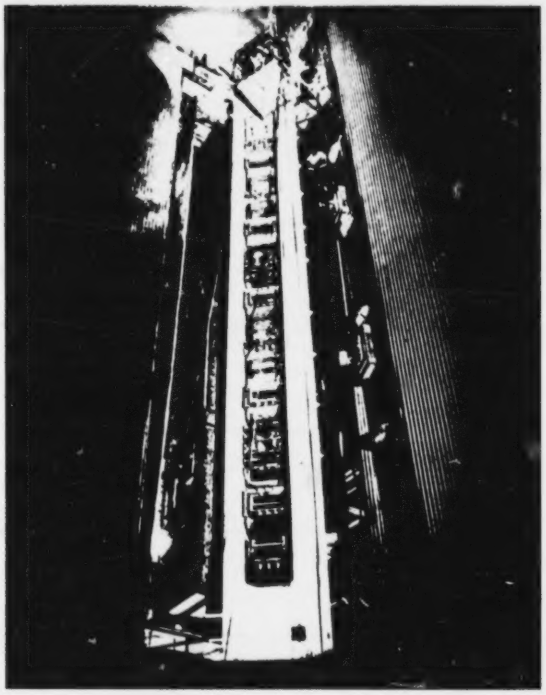
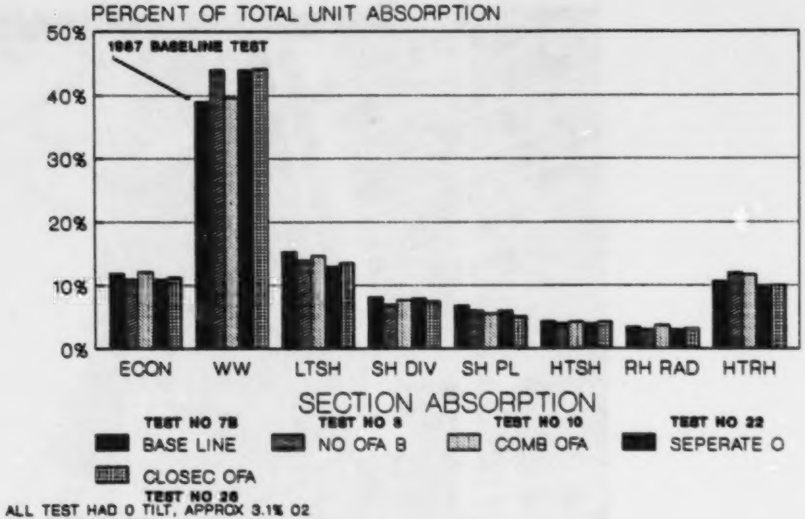


Figure 10. PM Retrofit Windbox Construction
Final Fit-up Into Furnace Corner



ALL TEST HAD 0 TILT, APPROX 3.1% O2
AND 300 MW LOAD

Figure 11. Steam Side Absorption Comparison of Baseline vs PM Firing Systems With and Without OFA

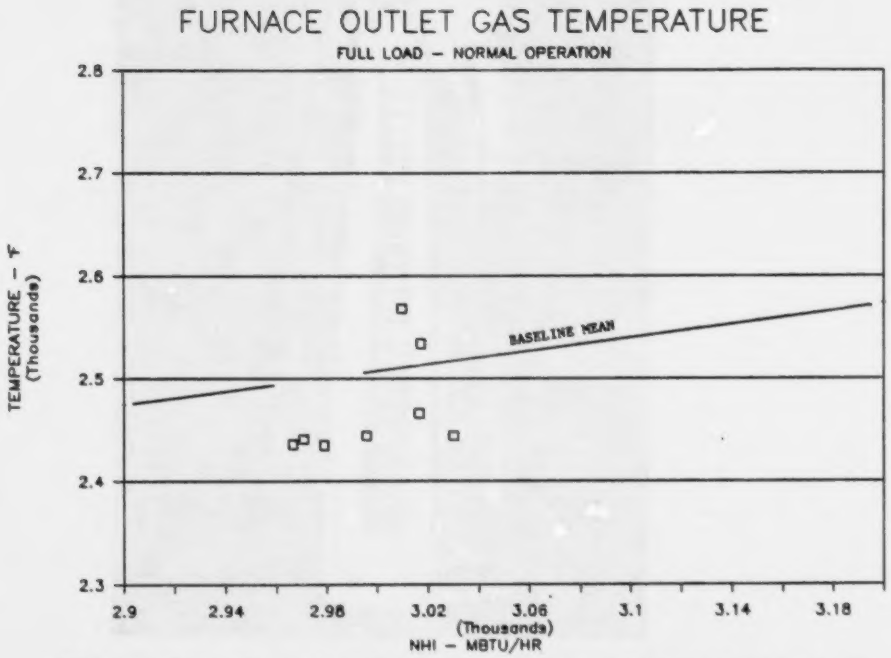


Figure 12. Furnace Outlet Gas Temperature Comparison Between The Mean Baseline Temperature And The Normal PM Operation (25% OFA) Temperatures Over Boiler Load

NO_X EMISSION RESULTS

KANSAS POWER & LIGHT COMPANY
LAWRENCE UNIT NO. 5

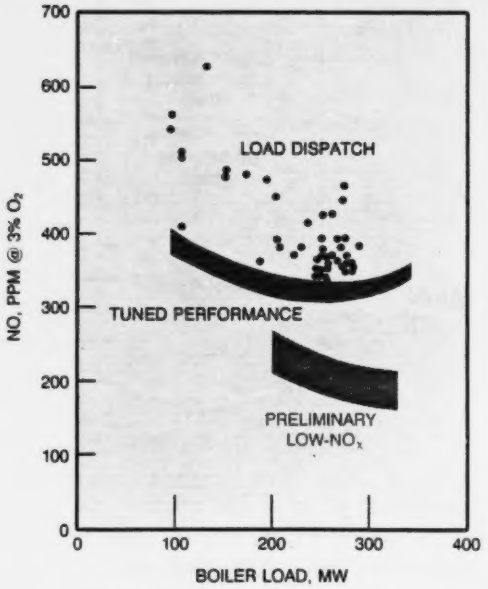


Figure 13. NOx Emission Performance Over Load

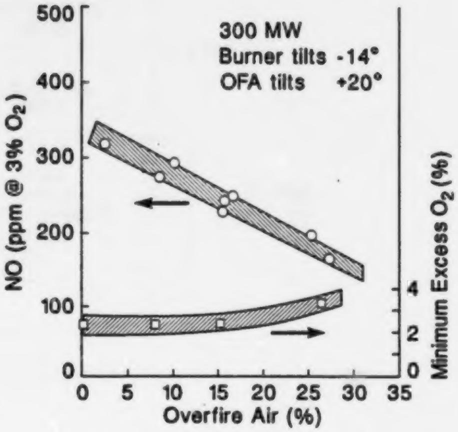


Figure 14. PM Firing System OFA Dependence

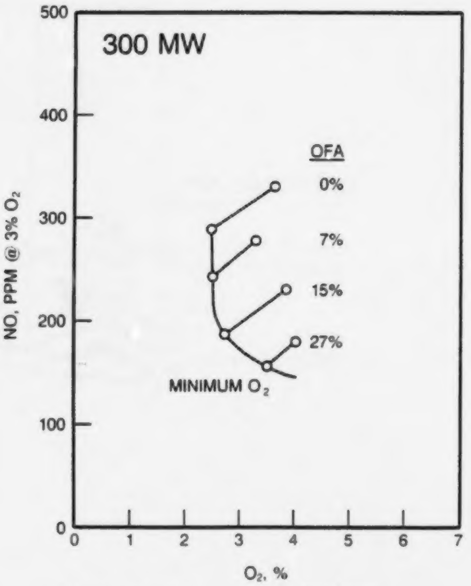


Figure 15. PM Firing System Oxygen Requirements

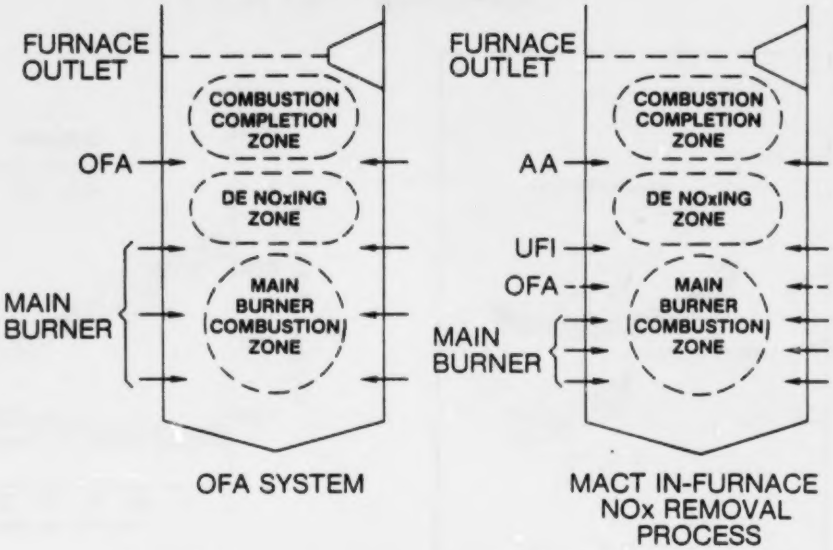

FURNACE OUTLET
COMBUSTION COMPLETION ZONE
OFA
DE NOxING ZONE
MAIN BURNER
MAIN BURNER COMBUSTION ZONE
OFA SYSTEM
FURNACE OUTLET
COMBUSTION COMPLETION ZONE
AA
DE NOxING ZONE
UFI
OFA
MAIN BURNER
MAIN BURNER COMBUSTION ZONE
MACT IN-FURNACE NOx REMOVAL PROCESS

Figure 16. Comparison of MACT In-Furnace NOx Removal Process With Conventional OFA Method

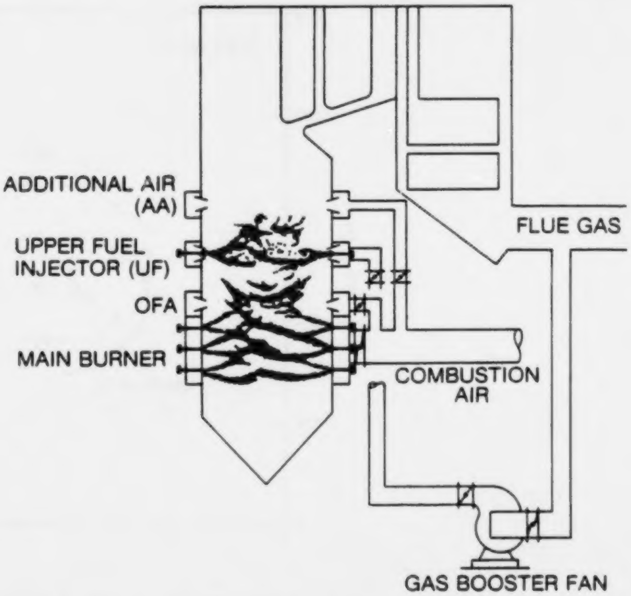

ADDITIONAL AIR (AA)
UPPER FUEL INJECTOR (UF)
OFA
MAIN BURNER
FLUE GAS
COMBUSTION AIR
GAS BOOSTER FAN

Figure 17. Schematic Diagram of MACT For Steam Generator

C-E SCR Experience in U.S.A.

Plant Name	Plant Type	System Supplier	Fuel Type	Treated Flue Gas Volume, SCFM	Start of Operation
Chevron U.S.A., Inc Richmond Refinery Richmond, CA	3 Process Heaters	CE	Process Gas	20500/16500/16550	July, 1984
Chevron U.S.A., Inc. El Segundo Refinery El Segundo, CA	Package Boiler	CE	Refinery Gas Future No. 2 Oil	85000	Feb., 1988
Corona Energy Partners Corona Cheese Factory	Heat Recovery Boiler	MHI/CE*	Natural Gas	294200	April, 1988
Simpson Paper Co.	Heat Recovery Boiler	MHI/CE*	Natural Gas	278700	May, 1988
Harbor Cogeneration Project Wilmington, CA	Heat Recovery Boiler	CE	Natural Gas Refinery Gas	528000	1st Quarter

*CE Scope Includes: SCR reactor chamber structure, monorail for catalyst removal, ammonia injection grid, ammonia supply skid and associated piping and dilution air fan/ductwork.

Table 2. C-E Domestic SCR Systems Experience List

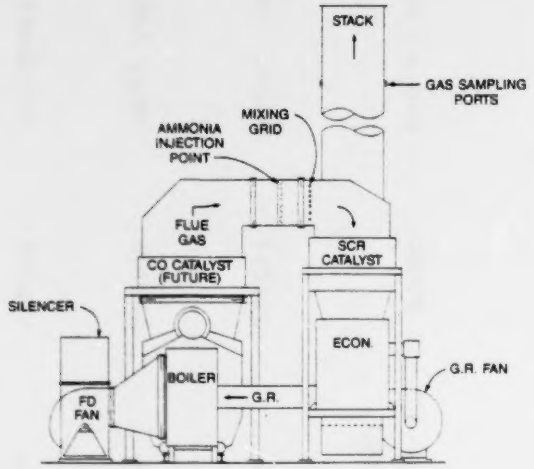
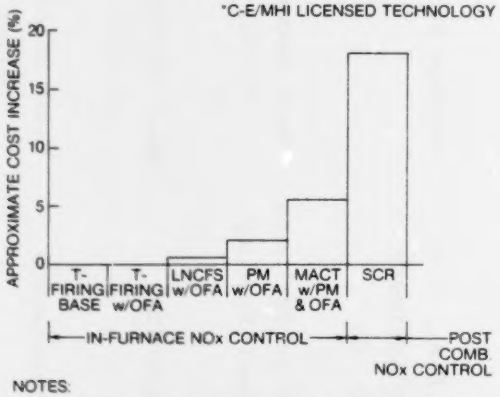

STACK
GAS SAMPLING PORTS
MIXING GRID
AMMONIA INJECTION POINT
FLUE GAS
SCR CATALYST
CO CATALYST (FUTURE)
SILENCER
ECON.
G.R. FAN
BOILER
G.R.
FD FAN

Figure 18. General Arrangement of a Typical SCR System

KEY

T-FIRING	TANGENTIAL FIRING
OFA	OVERFIRE AIR
LNCFS	LOW NOx CONCENTRIC FIRING SYSTEM
*PM	POLLUTION MINIMUM BURNER
*MACT	MITSUBISHI ADVANCED COMBUSTION TECHNOLOGY
*SCR	SELECTIVE CATALYTIC REDUCTION SYSTEM

*C-E/MHI LICENSED TECHNOLOGY



NOTES:

1. BASED ON MATERIAL AND CONSTRUCTION COSTS FOR A NEW 300 Mw COAL FIRED UNIT
2. SCR SYSTEM COSTS ARE BASED ON 80% NOx REMOVAL
3. SCR SYSTEM COSTS DO NOT INCLUDE NH_3 TANK FARM EQUIPMENT OR EXTERNAL STRUCTURAL SUPPORT STEEL
4. THESE COST APPROXIMATIONS ARE SUBJECT TO CHANGE DEPENDING ON SPECIFIC UNIT DESIGN REQUIREMENTS

Figure 19. Economic Comparison of Various NOx Reduction Techniques for Tangential Coal Fired Utility Boilers

The work described in this paper was not funded by the U.S. Environmental Protection Agency. The contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

STATUS OF NO_x CONTROL TECHNOLOGY AT RILEY STOKER

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E.L. Reicker
T. Davis

Riley Stoker Corporation
Worcester, Massachusetts

ABSTRACT

An overview of on-going efforts at Riley Stoker to develop improved low-NO_x combustion technologies for both new and existing boilers is presented. A new Controlled Combustion Venturi (CCV) burner design is described along with full-scale burner test data from the Riley Research coal burner test facility. NO_x reductions of 40 to 60% were achieved with this burner design. In addition, recent overfire air system operating experience is discussed. Field test data from a 400MW coal-fired utility boiler retrofitted with new overfire air NO_x controls are presented.

The application of NO_x controls to incineration and fluidized bed combustion are also reviewed. Pilot-scale test results from a municipal solid waste (MSW) combustor are compared with full-scale field data. Experiments have also been conducted addressing the effectiveness of gas reburning applied to mass burn incineration systems. The paper concludes with a brief summary on the status of NO_x controls for circulating fluidized bed boilers.

INTRODUCTION

The average age of the U.S. utility and industrial boiler population continues to rise, while acid rain legislation becomes increasingly likely. Several states have, or will soon enact NO_x control legislation of their own. NO_x control, therefore, may soon be required on boilers not currently regulated under Federal New Source Performance Standards (NSPS). NO_x control research, therefore, has remained an important element in Riley Stoker's product development and overall business strategies.

This paper provides an overview of recent efforts at Riley Stoker to develop low-NO_x combustion control technologies for both existing and new utility and industrial boiler systems. Overfire air and low NO_x burners continue to represent two of the most cost effective retrofit low-NO_x combustion control technologies for pre-NSPS boilers. In our update given at the 1987 Joint Symposium we discussed plans to upgrade our low-NO_x coal burner technology, the Controlled Combustion Venturi (CCV) burner, and to improve overfire air system performance on an existing utility coal-fired boiler. The results of these activities are presented here.

We will also discuss the development of NO_x controls for several new boiler technologies. Pilot-scale studies are underway to investigate the effectiveness of natural gas reburning in reducing NO_x emissions from municipal solid waste combustion. A new combustion test facility has been constructed to support this research. Circulating fluidized bed boilers have become the combustion technology of choice in many new industrial coal-fired boiler applications. Low combustion temperatures combined with staged combustion offer the potential for achieving significantly lower NO_x emission levels than conventional coal-fired systems. Riley Stoker is currently under contract with the U.S. Department of Energy to develop an advanced coal-fired fluidized bed combustion system capable of controlling NO_x emissions to 0.1 $lb/10^6$ Btu or less.

CCV BURNER DEVELOPMENT

The Riley Controlled Combustion Venturi (CCV) burner (U.S. Patent No. 4,479,442) was originally developed as a low-NO_x coal burner for wall-fired boiler retrofit applications. Our initial retrofit experience on three utility boilers was first discussed at the 1982 Joint Symposium(1). In order to extend the performance of this low-NO_x burner technology over a wider range of operating conditions additional design improvements have been developed and implemented. The performance objectives for this second generation CCV burner design were as follows:

- Improved mechanical reliability and operability of the secondary air register system.
- Reduced air side pressure drop requirements for wider retrofit application.
- Improved low-load operation.
- Maintain low-NO_x characteristics.

The second-generation CCV burner design is illustrated in Figure 1. NO_x control is still achieved through a patented venturi coal nozzle and low swirl coal spreader design. Control of fuel and air mixing is achieved by separating the primary air/coal stream into fuel-rich and fuel-lean layers before mixing into the secondary air. In addition to the venturi nozzle, the second-generation CCV burner incorporates a new secondary air register design for swirl and air flow control. Curved, overlapping air register turning vanes provide improved swirl control at lower pressure drop. Secondary air flow is controlled by a movable shroud that slides over the secondary air register entrance. Independent control over both the shroud and air turning vane positions offers significant flexibility in controlling combustion even at low load. Inlet secondary air velocity is controlled at low loads by partially closing the shroud. As as result, swirl and flame stabilization are maintained even under low load staged combustion operation. The entire air register mechanism has been redesigned and moved to the burner front plate away from the hot firing wall for improved mechanical reliability.

A 100 million Btu/hr prototype of this second-generation CCV burner has been built and demonstrated in Riley Research's Coal Burner Test Facility (CBTF) located in Worcester, Massachusetts. This facility is designed to simulate near field combustion conditions in full-scale furnaces. A more complete description of this facility was presented at the 1985 Joint Symposium(2). Both staged and unstaged burner tests were conducted. Staged combustion was achieved by introducing a portion of the combustion air downstream of the burner simulating operation with overfire air. Results comparing CCV burner emissions with a Riley pre-NSPS Flare burner are shown in Figure 2. In these tests, primary or burner zone stoichiometry was varied from 0.8 to 1.23 (unstaged). CCV burner NO_x emissions were 40 to 60 percent lower than emission levels established with the Flare burner. As found in previous studies, NO_x and CO emissions varied with coal spreader configuration and the amount of overfire air. Spreader design, which controls flame length, allows the burner to be tuned to various furnace geometries. Flame lengths from 9-20 feet were observed during the tests. Scale-up of pilot-scale emission data to field conditions also depends on other considerations such as fuel type and furnace design parameters(3).

The following burner performance characteristics were also established during the pilot-scale testing:

- Turndown ratio of 3 to 1
- Combustion efficiency of 99.6 percent
- A reduction in windox furnace pressure drop from 8-10"wc to 4"wc
- Improved mechanical reliability

Second generation CCV burners are now being proposed for a number of utility and industrial boiler retrofit applications both in the U.S. and Far East.

NEW OVERFIRE AIR APPLICATION

Riley Stoker has retrofitted overfire air systems on both coal and oil/gas fired boilers. A recent application included field modifications to an existing overfire air system on a 400MWe coal-fired Turbo furnace. This unit was designed in 1974 to meet the 1971 NSPS of 0.7 $lb/10^6$ Btu. The objective of the field modifications were: 1) increase boiler firing capacity to 105-110 percent of maximum continuous rating (MCR), 2) reduce NO_x emissions to 0.6 $lb/10^6$ Btu at 105 percent MCR, and 3) maintain previous combustion efficiency at lower NO_x operation. An additional objective was to retain the existing burner openings and avoid extensive pressure part modifications.

The overfire air system design and modified design are illustrated in Figure 3. The Riley Turbo furnace is characterized by a venturi shaped lower furnace. Burners are installed in single rows on opposite downward facing arches. This particular unit is equipped with 24 Riley Directional Flame burners. Overfire air ports are installed on the vertical furnace wall directly above each burner. In the original design, overfire air was supplied from the main burner windbox. Modifications included revision to the air supply duct system and installation of a separate overfire air plenum or windbox for improved air flow control. The overfire air ports themselves were redesigned for increased flow capacity based on guidelines developed under an earlier EPRI Study(4). Overfire air velocity was increased for better jet penetration across the furnace and to enhance mixing in the burnout zone. Wing overfire ports between the end burners and furnace walls were added to improve mixing and burnout in the corners and along the furnace side walls. Underfire air ports beneath the burners were installed to improve lower furnace combustion efficiency and to maintain an oxidizing environment along the lower furnace walls during staged combustion. No additional fan capacity was required to implement these changes.

Although the original Directional Flame burners were retained, a number of burner design modifications were incorporated. Major burner modifications are described in Figure 4. These modifications were required to increase firing capacity and improve flame stability under more deeply staged combustion. The Riley Direction Flame burner utilizes axial and parallel secondary air and primary air/fuel streams. Air and fuel are introduced through slots formed in the furnace wall. Adjustable air vanes above and below each pair of coal nozzles direct secondary air into or away from the primary stream. Burner modifications included the elimination of the coal spreader and the substitution of a converging coal nozzle. The coal spreader was removed to eliminate a high wear burner component. The converging nozzle was added to prevent flame detachment. A perforated plate was also inserted in the center air slot to maintain secondary air velocity under more deeply staged conditions. Finally, turning vanes near the entrance of the coal nozzles were redesigned to provide a more uniform distribution of primary air and fuel within the coal nozzle. The design of each of these coal nozzle components was based on the results of cold flow model studies.

All of the retrofit objectives were met. As shown in Figure 5, the original overfire air system design, while meeting NO_x compliance at 100 percent MCR, did not provide an adequate amount of air staging to achieve the compliance NO_x level of 0.7 $lb/10^6$ Btu at 105 percent MCR. However, field testing demonstrated that the revised NO_x limit emission of 0.6 $lb/10^6$ Btu is achieved with the modified overfire air system at 105 percent MCR. The addition of the redesigned coal pipe turning vanes, described above, further enhanced overall system NO_x control capabilities. In addition to reducing NO_x, these turning vanes also led to lower furnace exit gas temperature; thereby, eliminating the need for reheat spray above 100% MCR.

Carbon burnout did not deteriorate with the new system even under the higher load and low-NO_x operating conditions. However, in addition to burner modifications, mill system tuning was required to maintain this level of performance. This facility is equipped with three Riley ball tube mill coal pulverizers.

This case study emphasizes the importance of a systems approach when evaluating retrofit low-NO_x combustion control options. All aspects of the combustion system must be considered including the burners, overfire air ports, windbox, combustion controls, and pulverizer system.

NO_x CONTROLS FOR MUNICIPAL SOLID WASTE COMBUSTION

The Riley Research Center is currently engaged in a research and development program with the Institute of Gas Technology and the Gas Research Institute to reduce emissions from mass burn resource recovery boilers. The primary objective of this program is to determine the effectiveness of an in-furnace control technology known as reburning in reducing NO_x formed during municipal solid waste (MSW) combustion. In this study natural gas is introduced as a reburning fuel above a modern mass burn combustion grate. Pilot-scale studies on oil and coal-fired systems have shown natural gas to be an effective reburning fuel, particularly at low-NO_x emission levels(5).

Riley recently modified its 3 million Btu/hr pilot combustion facility to include MSW. As shown in Figure 6, the lower furnace has been reconfigured to accommodate a Riley/Takuma mass burn combustion system. The combustion system consists of a step grate stoker (Figure 7) equipped with individual undergrate air control for drying and ignition, combustion and burnout. Overfire air is used to complete combustion. The pilot facility is capable of burning approximately 450 lb/hr or 5.5 tons/day of shredded refuse. The grate and lower furnace are designed to simulate conditions at a 100 ton/day Riley/Takuma resource recovery boiler located in Olmsted County, Minnesota. A comparison of pilot-scale baseline emissions data with full-scale emission data is given in Table 1.

The test facility also has provisions for introducing natural gas and recirculated flue gas at various locations above the grate in order to create a fuel rich NO_x reduction zone above the main heat release zone. Up to 40 percent of the total furnace load can be fired in the reburning zone. Flue gas is introduced with the natural gas to enhance mixing and reduce excess air requirements. Conventional MSW systems operate with excess air levels of 80% or more.

Tests have been conducted in this facility to determine the influence of various MSW combustion and reburning zone parameters on reburning efficiency. Preliminary test results are shown in Figure 8. These results will be discussed in greater detail later in this Symposium(6). However, a 50 percent reduction in MSW NO_x emissions was achieved with 7 to 15 percent natural gas as a reburning fuel. The effectiveness of reburning was found to be a function of reburning zone stoichiometry and residence time, and gas injection location. Future testing will further explore the impact of these parameters on the reburning process.

CIRCULATING FLUIDIZED BED COMBUSTION

Considerable experience is now being gained on atmospheric fluidized bed boilers. In recent years, the development of this technology has focused on the circulating fluidized bed (CFB) boiler. Since 1983, 66 CFB boilers have been sold in the U.S. Those units represent over 22 million pounds per hour of steam capacity. Riley Stoker and its liscensee, Mitsui Engineering and Shipbuilding Ltd. of Japan, have designed and constructed nine coal-fired CFB boilers varying in individual capacity from 150,000 to 660,000 lb/hr of steam. The Riley system is based on a technology known as Multi-solids Fluidized Bed Combustion (MSFBC)(7).

Riley coal-fired MSFBC boilers use limestone to control SO_2 emissions. MSFBC systems, therefore, are designed to operate at temperatures of 1500 to 1700°F for efficient limestone utilization and SO_2 control. Each MSFB boiler incorporates staged combustion for enhanced NO_x control. As as result, NO_x emissions from coal fired MSFBC units are below current emission limits. Recent field tests in both the U.S. Japan have demonstrated that MSFBC boilers are capable of operating at NO_x emission levels below 0.3 $lb/10^6$ Btu. Emissons vary from unit to unit as a function of fuel type and system design parameters such as primary zone stoichiometry, primary zone residence time, and temperature(8). In 1987, Riley Stoker was awarded a U.S. DOE contract to investigate advanced fluidized bed combustion concepts applicable to small coal-fired industrial and commercial boilers. One of the goals of this program is to achieve NO_x emission levels of 0.1 $lb/10^6$ Btu or less with high combustion efficiency.

Riley Stoker is currently installing at its Riley Research Center a 7 million Btu/hr circulating fluidized bed test facility to study various staged combustion approaches. The combustor, shown in Figure 9, is over 60 feet tall and capable of simulating a variety of staged combustion configurations and operating conditions. Combustion testing will begin this spring.

SUMMARY

Retrofit combustion controls in the form of low-NO_x burners and improved overfire air systems are commercially available. NO_x reductions of up to 60 percent are possible with these technologies. A second-generation CCV burner has been developed offering greater reliability and extended operating range. Full-scale operating experience is still required on more advanced combustion techniques, such as advanced air staging and reburning, before these technologies achieve commercial status.

Combustion modification techniques originally applied on oil and coal-fired systems are now being considered for refuse fired boilers. The application of NO_x combustion controls to incineration systems faces many unique challenges. Refuse, such as municipal waste, is an extremely heterogeneous and variable fuel. The combustion history is much less well defined. In comparison with conventional fuels, combustion conditions are apt to vary considerably over both time and space. Resource recovery boilers also operate at relatively low temperature and high excess air levels. A new pilot-scale test facility is being used to improve our understanding and design of modern refuse fired combustion systems.

Commercial operating experience is being rapidly acquired on coal-fired circulating fluidized bed boilers. These systems offer greater fuel flexibility and provide combined NO_x and SO_2 control.

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7. W. Place and J. Coulthard, "Practical Aspects of Multi-solid Fluid Bed (MSFB) Systems," Presented at the Second International Conference Circulating Fluidized Beds, Campienge, France, March 1988.

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Table 1

COMPARISON OF PILOT-SCALE AND FULL-SCALE MSW TEST DATA FOR A RILEY/TAKUMA MASS BURN COMBUSTION SYSTEM

	Full-Scale	Pilot-Scale
MSW Heating Value, Btu/lb.	6037	5447
Load, 10^6 Btu/hr.	37.5	2.36
Excess Air, %	73	70
OFA, %	34	38
Combustion Products		
O_2, % (1)	9.3	8.7
CO_2, % (1)	10.1	10.9
CO, ppm (2)	29	27
NO_x, ppm (2)	134	142
Furnace Exit, Temp., °F	1620	1570
Residence Time to Furnace Exit, sec.	3.8	2.0

(1) As measured
(2) Based on 12% O_2

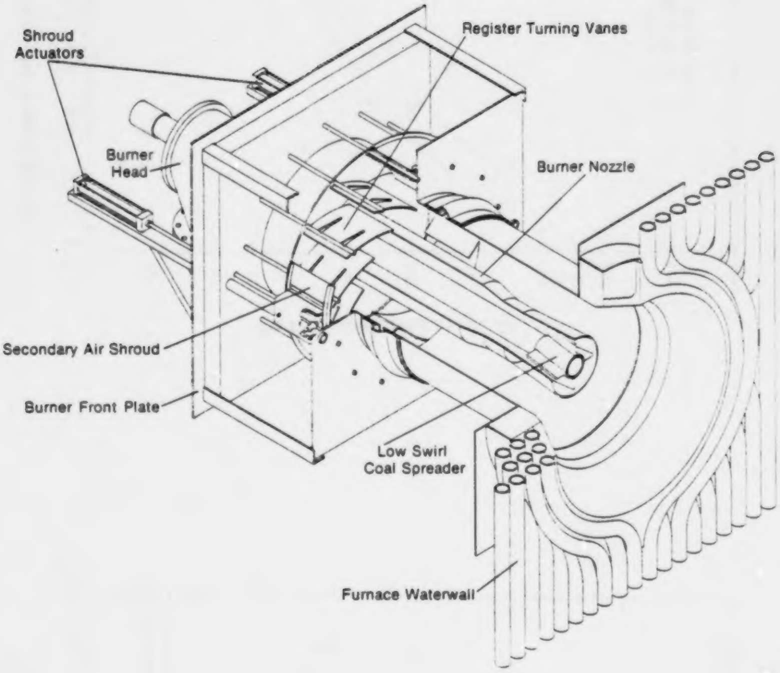

Shroud Actuators
Register Turning Vanes
Burner Head
Burner Nozzle
Secondary Air Shroud
Burner Front Plate
Low Swirl Coal Spreader
Furnace Waterwall

Figure 1. Second Generation CCV Burner with New Secondary Air Register and Movable Shroud

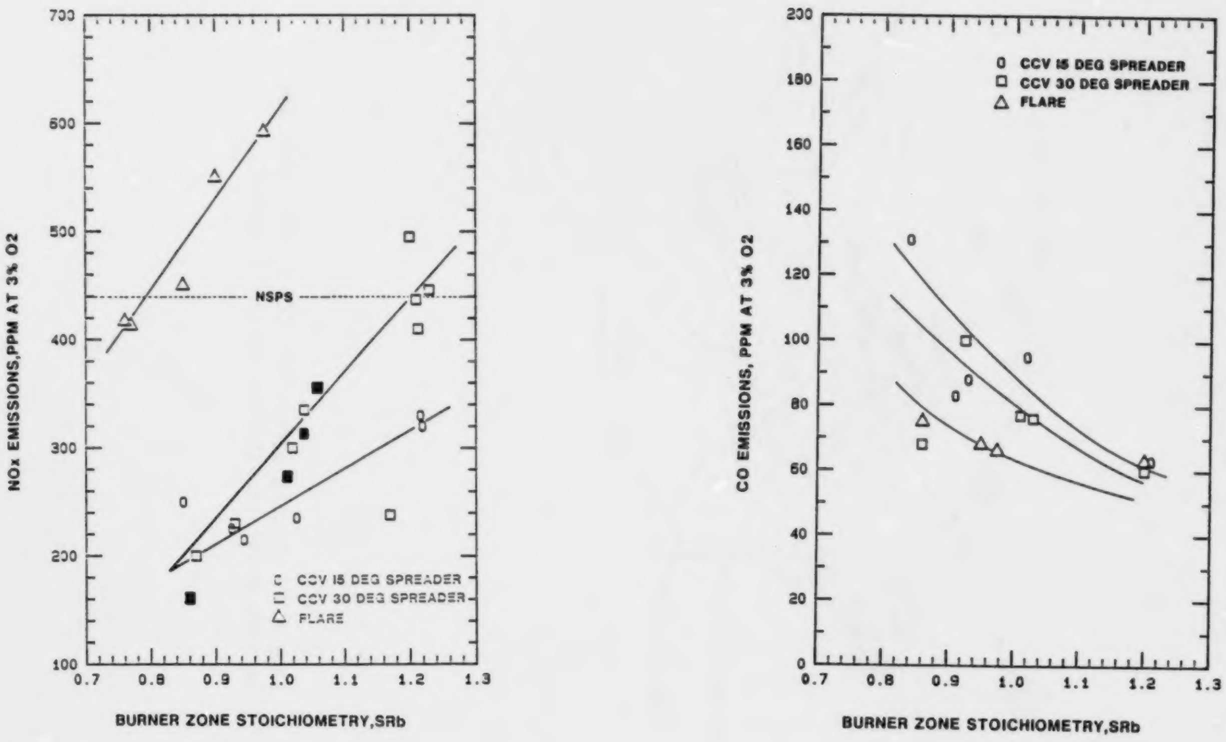


Figure 2. Comparison of 100 Million Btu/hr Pilot-Scale NOx and CO Emissions for the CCV and Flare Burners (open symbols Pennsylvania bituminous, solid symbols Illinois bituminous).

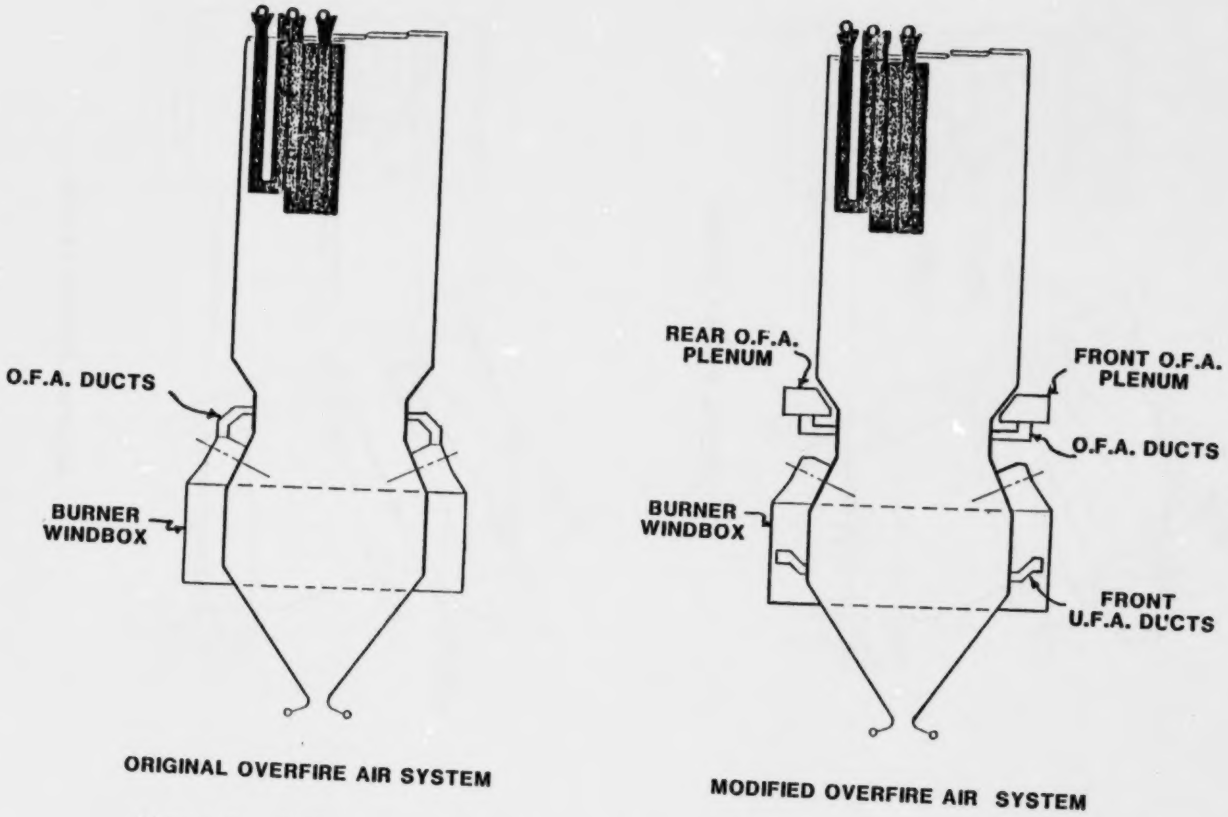
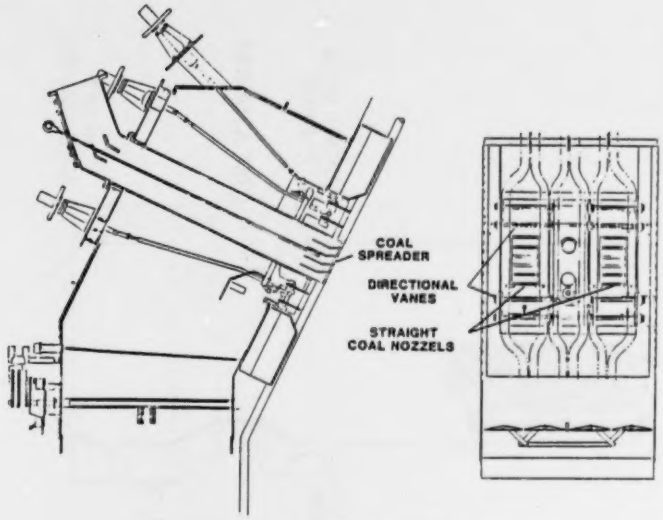
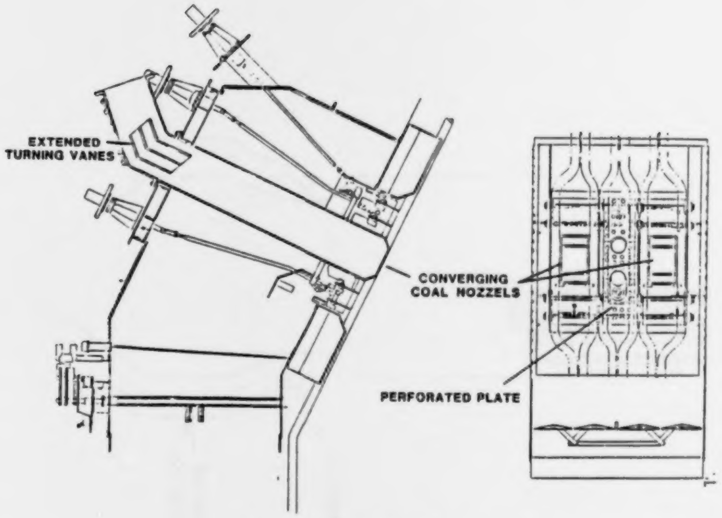

O.F.A. DUCTS
BURNER WINDBOX
ORIGINAL OVERFIRE AIR SYSTEM
REAR O.F.A. PLENUM
BURNER WINDBOX
FRONT O.F.A. PLENUM
O.F.A. DUCTS
FRONT U.F.A. DUCTS
MODIFIED OVERFIRE AIR SYSTEM

Figure 3. Comparison of Original and Retrofit Overfire Air System Designs Tested on a 400 MW Coal-Fired Turbo Furnace


COAL SPREADER
DIRECTIONAL VANES
STRAIGHT COAL NOZZELS

ORIGINAL BURNER DESIGN


EXTENDED TURNING VANES
CONVERGING COAL NOZZELS
PERFORATED PLATE

MODIFIED BURNER DESIGN

Figure 4. Original and Modified Direction Flame Coal Burner

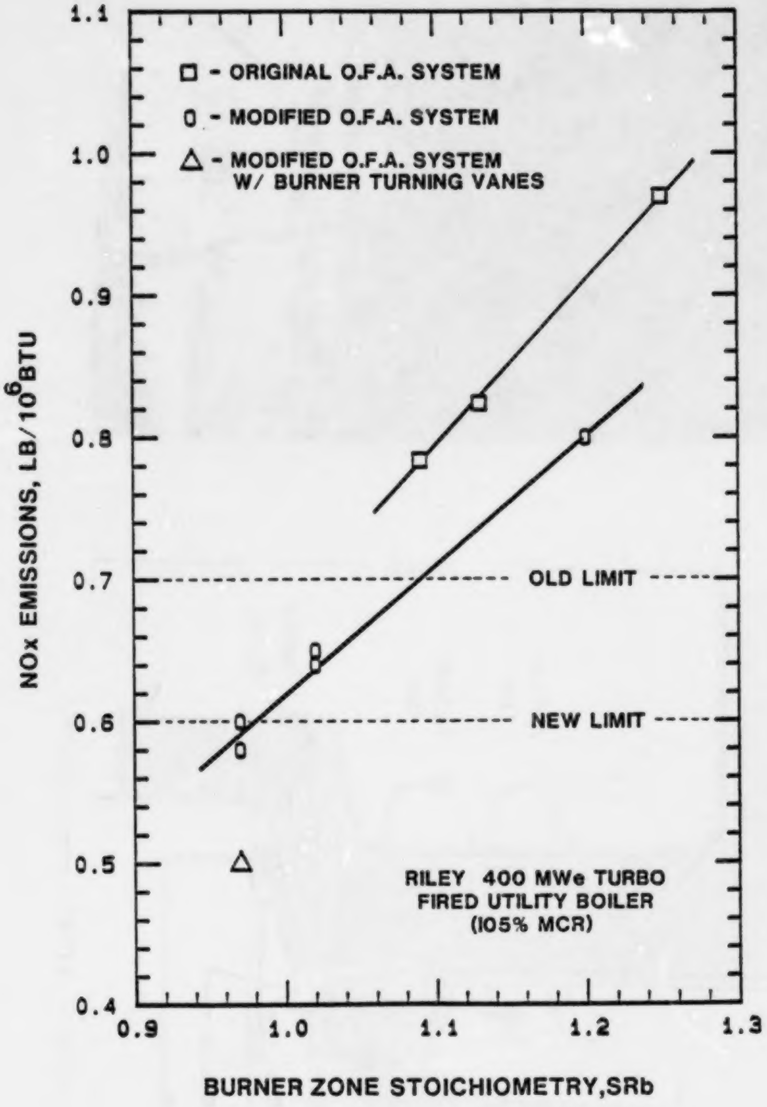
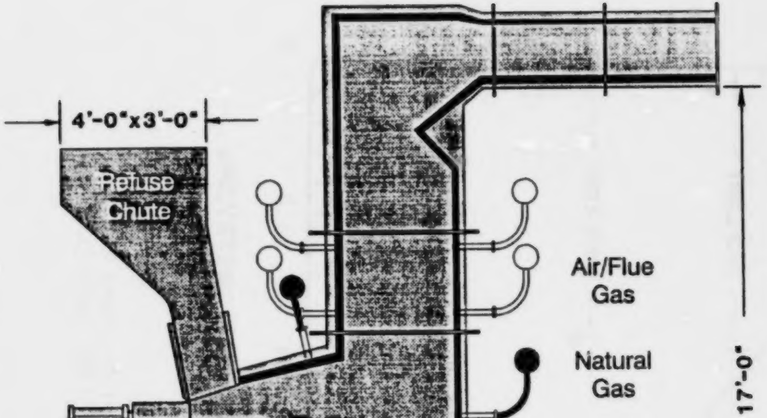
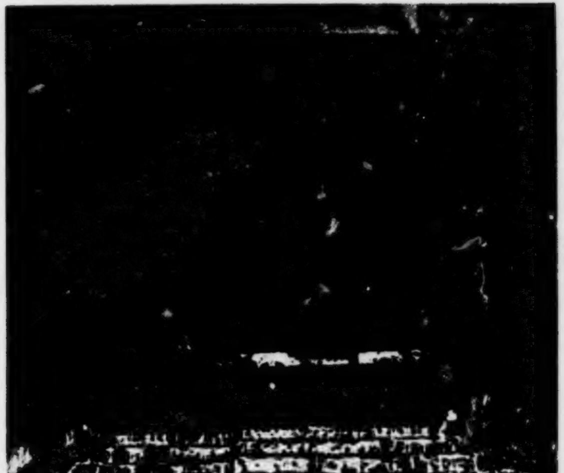


Figure 5. The Effect of Overfire Air on Coal-Fired Turbo Furnace NOx Emissions

Reproduced from
best available copy.


4'-0"x3'-0"
Refuse
Chute
Air/Flue
Gas
Natural
Gas
17'-0"



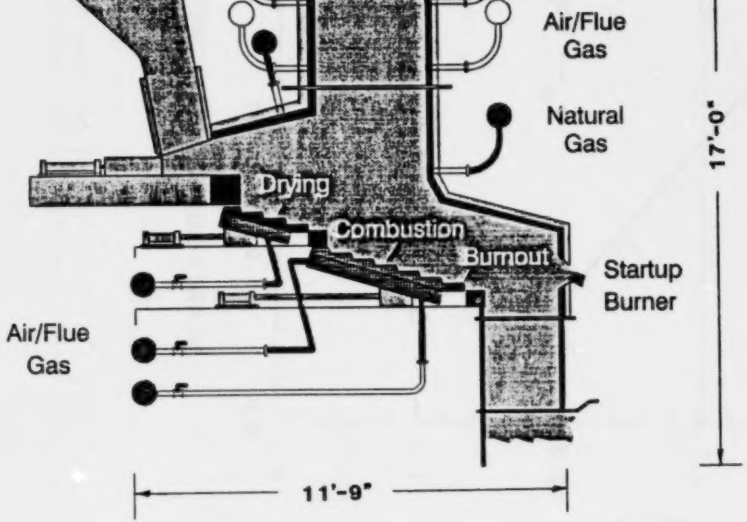

Air/Flue
Gas
Natural
Gas
17'-0"
Drying
Combustion
Burnout
Startup
Burner
Air/Flue
Gas
11'-9"

Figure 6. Riley 3 Million Btu/hr Pilot-Scale MSW Combustion Facility

Figure 7. Pilot-Scale Stepped Combustion Grate

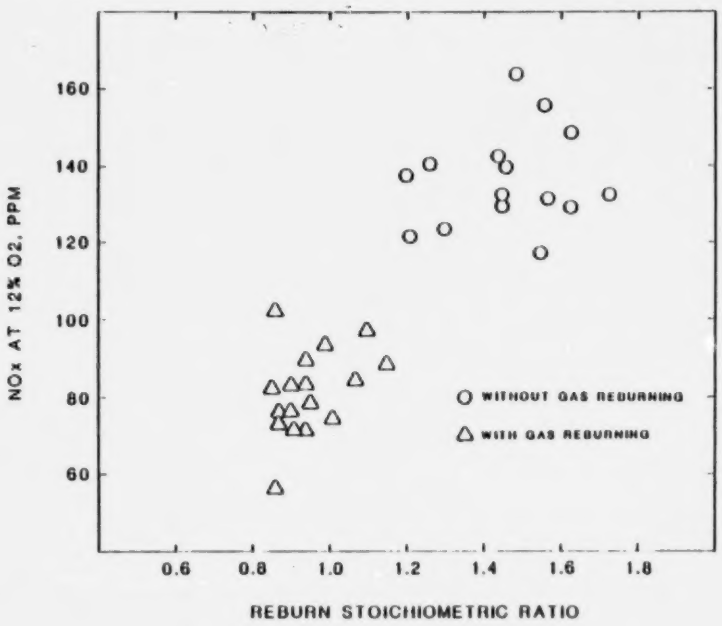


Figure 8. The Effect of Natural Gas Reburning on Pilot-Scale NOx Emissions from Municipal Solid Waste Combustion

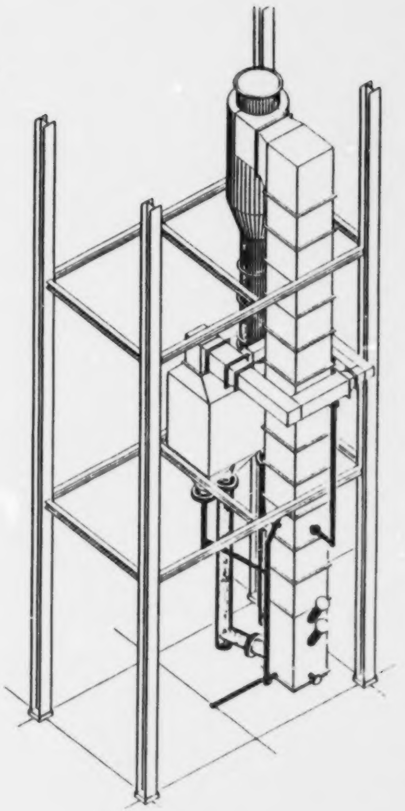


Figure 9. Riley Stoker's 7 million Btu/hr Pilot-Scale Circulating Fluidized Bed Test Facility

Session 5A

ADVANCED COMBUSTION TECHNOLOGY

Chairman: N. Holt, EPRI

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THE CONVERSION OF FUEL-NITROGEN TO NO_x IN CIRCULATING FLUIDIZED BED COMBUSTION

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ABSTRACT

Circulating Fluidized Bed (CFB) combustion has become accepted as a commercial technology for burning coal and low grade fuels in an economical and environmentally acceptable manner. One of the foremost advantages of CFB technology is low NO_x emission levels. With staged combustion and a series of NO_x formation and destruction reactions occurring in the combustor, NO_x emission from coal combustion in a CFB is quite low.

This paper discusses the mechanism and the interaction of various NO_x formation and destruction reactions on the conversion of fuel-nitrogen to NO_x in a CFB. Experimental data from CFB units will be presented to illustrate the discussions. The effect of fuel type, fuel-nitrogen split to volatile-nitrogen and char-nitrogen, and their conversion efficiency on NO_x emission are presented. Additional NO_x control methodologies for meeting more stringent emission standards will also be discussed.

INTRODUCTION

With the growing concern of acid rain and photochemical smog, NO_x and SO_2 emission from combustion sources have received strong attention in recent years (1,2,3). In the pursuit of the control and reduction of NO_x and SO_2 emission, many new technologies which involve either in-furnace combustion modifications or post-combustion reduction, have been developed (4). With its many design advantages, circulating fluidized bed combustion (CFBC) has been accepted as a commercial technology for burning coal and low grade fuels in an economical and environmentally acceptable manner. The specific features and advantages of the AHLSTROM circulating fluidized bed design will be presented in the next section. The lower operating temperature and a series of NO_x reduction reactions have resulted in lower NO_x emission in both bubbling and circulating fluidized bed combustors as opposed to that from pulverized coal furnaces and stokers. Staged combustion, which has been found to be successful in reducing NO_x emission, is particularly suitable for circulating fluidized bed combustors. Data from commercial units have shown that the NO_x emission from CFB is lower than that of bubbling fluidized bed and pulverized coal furnaces (5). This paper reviews the factors that contribute to the lower NO_x emission in circulating fluidized bed combustors. The mechanism and interaction of various NO_x formation and destruction reactions on the conversion of fuel-nitrogen to NO_x in a CFB will be discussed.

MAIN FEATURES OF AHLSTROM PYROFLOW® CFBC

The primary components of an Ahlstrom circulating fluidized bed boiler are shown in figure 1. It consists of a combustor chamber, a cyclone separator, a return leg and loopseal for recirculation of the bed particles. The combustion chamber is enclosed with water-cooled tubes and a gas-tight membrane. The lower section of the combustor is covered with refractory and with openings for introducing fuel, limestone, secondary air, recycled ash, a gas or oil burner for startup and bottom ash drain. The majority of the combustion process occurs in the lower section and heat removal is achieved mainly by particle convection and radiation in the upper section of the combustor. The cyclone is refractory-lined and is designed to separate the entrained solids from the hot flue gas and return the solids through the return leg and loopseal. The loopseal provides a seal for backflow of gas and has no movable mechanical parts. The gas velocity employed in CFB is in the range of 15-20 ft/sec. The air distribution include primary air, secondary air, transport air for fuel and limestone feed, air to loopseal and fluidizing air to ash classifier. The bottom ash classifier is designed to remove larger bed particles and recycle small particles back to the combustor for better heat transfer. The operating bed temperature is usually in the range of 1570-1630 °F. The coal and limestone feed size is normally 1/4" x 0 and 18 mesh x 0 respectively.

The circulating fluidized bed combustor has the following inherent advantages over conventional combustion systems and bubbling fluidized bed system:

- fuel flexibility
- low pollutants emission
- lower NO_x emission
- lower limestone consumption for sulfur capture
- higher combustion efficiency
- higher load turndown ratio
- operational simplicity and reliability

The above advantages have thrust CFBC into the fore-front of industrial boilers market in recent years. In addition, the Colorado-Ute 110 MWe utility project has shown promise in the scale-up of this technology.

FUEL-NITROGEN CONVERSION PATHWAYS

'Thermal NO', which is formed from nitrogen in air following Zeldovich mechanism, contributes to less than 10% of the total NO emission from fluidized bed combustors because of the lower, uniform bed temperature (6,7). It has been proven by studies (8,9) in which nitrogen in oxygen mixture has been replaced by argon in oxygen as fluidizing medium. Therefore, NO_x emission from fluidized bed combustors is mainly from the oxidation of fuel-nitrogen.

Figure 2 is a schematic summarizing the pathways in the conversion of fuel-nitrogen in fluidized bed combustors (10). Upon heating, fuel particles release volatiles including nitrogenous compounds such as HCN and NH_3. The fate of the fuel-nitrogen then depends on whether it follows the volatile-nitrogen pathway or the char-nitrogen pathway. In the case of volatile-nitrogen, it can be assumed that the volatile-nitrogen species are released rapidly, and will diffuse and react in the gaseous phase outside the boundary layer of the particle. The conversion efficiency of these nitrogenous species to NO will depend on the local availability of oxygen and the temperature. On the other hand, in the char-nitrogen pathway, nitrogen retained in the char after devolatilization are converted to NO during char combustion. However, due to the heterogeneous reactions between NO and char as well as NO and CO over char, NO formed can be reduced to NO_2 as it diffuses out from the pores of the char particle. The NO escaped from the char particles can also be reduced by volatile nitrogenous species in the gas phase to N_2. Also, the NO formed from volatile-nitrogen can diffuse to the char surface and be reduced to N_2. Nevertheless, several studies (11,12) have shown that the conversion efficiency to NO from volatile-nitrogen is generally higher than that from char-nitrogen.

Even though the pathways for conversion of fuel-nitrogen can be described adequately by figure 2, the interaction of the fuel-nitrogen chemistry with the environment in the combustor created by the design and operating conditions of the circulating fluidized bed combustor makes it difficult to predict NO_x emission. In order to determine the relative contribution of volatile-nitrogen and char-nitrogen to NO_x emissions and identify potential strategies for the control of NO_x emissions, Beer et al. (13) and Lee et al. (14) have developed a mechanistic NO_x emission model based on considerations of the evolution and subsequent transformations of fuel-nitrogen to NO_x and N_2 for fluidized bed combustors. Recently, Johnsson (15) has developed a detailed kinetic model for the oxidation of volatile-nitrogen and the reduction of NO for fluidized bed combustor. It includes 13 homogeneous and heterogeneous reactions. A single-phase plug flow reactor model was used to evaluate the kinetic model. Johnsson has concluded that more information on the kinetics for the heterogeneous catalytic reactions is needed before detailed modeling of NO formation in fluidized bed combustors is possible.

The important reactions in the fuel-nitrogen conversion pathway in a CFB are summarized in table 1. The main homogeneous reactions involve the oxidation and reduction reaction of volatile-nitrogen in the form of NH_3. The main heterogeneous reactions involve the NO reduction by char and the NO + CO reduction reaction over char. The main catalytic reaction involve the oxidation of volatile-nitrogen (NH_3) over calcined limestones.

An investigation of the factors affecting the pathway on the conversion of fuel-nitrogen to NO, the effect of the fuel composition and the operating conditions are discussed below.

Effect Of Fuel-nitrogen Content

An upper bound for fuel-nitrogen contribution to NO_x emission can be obtained from the fuel-nitrogen content. Coal-bound nitrogen occurs in aromatic ring structures such as pyridine, picoline, quinoline and nicotines. The nitrogen content of typical American coals ranges from 0.5 to 2.0 percent. However, in a number of Ahlstrom pilot plant tests, the total nitrogen content has found not to be in direct relationship with NO_x emission. Even when the difference in heating value of different fuels is corrected by investigating the NO_x emission as a function of total nitrogen mg/MJ of fuel, no direct relationship is found. This implies that burning a high nitrogen content fuel will not necessarily results in higher NO_x emission from CFB. The heating value of the fuel would affect the total nitrogen feed rate into the combustor for a given boiler load. This in turn can affect the NO emission ppm value. Therefore, the conversion efficiency for fuel-nitrogen to NO would provide better comparison for different fuels than an absolute ppm value for NO_x emission.

CONVERSION EFFICIENCY OF FUEL-NITROGEN TO NO

There are many factors which either directly or indirectly affect the final conversion of fuel-nitrogen to NO in a CFB. They include the fuel-nitrogen split, the reactivity of the fuel, the sulfur content and retention requirement, the reactivity of limestone and particle size as well as the operating conditions such as bed temperature, excess air ratio and primary air/secondary air split. These factors are discussed below.

Effect Of Fuel-nitrogen Split

During the thermal decomposition reactions of fuel particles, some of the nitrogenous species in the fuel matrix are released with the volatiles. The evolution of the nitrogenous species is important in determining the final NO emission because of the difference in conversion efficiency for volatile-nitrogen and char-nitrogen. They are usually in the form of HCN or ammonia. The yield, relative distribution and release rate of these two nitrogenous species depend primarily on coal rank, heating rate and final particle temperature.

Pohl et al. (11) have studied the fuel-nitrogen release as volatiles by measuring the percentage retention of nitrogen in char produced by heating samples of coal in crucibles until the weight approached a constant value. The results have shown that in the operating temperature range of a CFB, the volatile-nitrogen evolved is shown to be 18-38% for bituminous coal and 10-22% for lignites.

Solomon (16) has studied 13 different coal types and reported that coal nitrogen is contained almost entirely in tightly bound rings which are released without breakage in the tar during the initial stage of devolatilization and the remainder are released at higher temperatures when rings are ruptured.

Song et al. (17) have studied the fate of fuel nitrogen during pyrolysis and oxidation in the temperature range of pulverized coal combustors using the drop tube furnace. They found that increase in temperature increases the volatile fraction but decreases the efficiency for converting to NO_x. In addition, oxidation experiments on chars indicates the non-selectivity between nitrogen and carbon during oxidation but the char nitrogen may undergo pyrolysis in parallel with the oxidation. Also, Pohl and Sarofim (11) have shown using drop tube furnace that the conversion efficiency of volatile-nitrogen is higher than char-nitrogen.

Chan and Lee (18) have studied the conversion of char-nitrogen to NO in a 7 cm ID fluidized bed reactor and concluded that the conversion of char-nitrogen to NO decreases with the increase in particle size and bed temperature. However, there is a minimum of conversion near 15% O2 in the range of 3 to 21%. The conversion efficiency to NO ranges from 5 to 25 % in that study with Mississippi lignite char.

Since the conversion efficiency of volatile-nitrogen is generally higher than that of char-nitrogen, it is expected that the volatile nitrogen content would have an important effect on the NO_x emission. Research studies at the Hans Ahlstrom Laboratory have investigated the relationship of the NO_x emission with the fuel volatile-nitrogen content for different fuels. The different fuels were burned in the 1.5 MW circulating fluidized bed combustor and the NO_x emissions were measured. Chemical analysis of the fuels were obtained and volatile-nitrogen fraction determined from the subtraction of the remaining char nitrogen from total fuel-nitrogen after the fuel has been devolatilized at 900 °C in an oven. The chemical analysis results of the fuels are shown in table 2. The typical operating conditions for these experimental runs were: Vg = 4.5 - 5.4 m/s, T= 850 - 920 °C, Primary air: 55-65%, Exit O_2 concentration (wet): 3-4 %. The results of these studies are plotted as the conversion efficiency of fuel-nitrogen versus volatile-nitrogen content in figure 3. It is shown that a good correlation is obtained. As the volatile-nitrogen content increases from 11% to 46.67%, the conversion efficiency increases from 4.7% to 12%. In figure 4, the fuel-nitrogen % is plotted against volatile % (d.a.f.) and a reasonably good correlation is obtained. The fuel volatile-nitrogen content increases with the fuel volatiles content in d.a.f. basis. Therefore, a plot of conversion efficiency to NO versus volatile % (d.a.f.) is obtained and shown in figure 5. As the volatile % (d.a.f.) increases, the conversion efficiency to NO increases in the CFB. Both correlations in figures 3 and 5 are shown to be reasonably good. It is, however, simpler to obtain volatile content information. There are exceptions to these correlations as expected because of the complicated interactions of different parameters in CFBC.

Effect Of Fuel Reactivity

The reactivity of the fuel depends on the volatile content and the reactivity of the char. The reactivity of the char depends primarily on the porous structure and the available active sites. A higher reactivity of the char would give rise to lower carbon loading in the combustor. A lower char concentration in the combustor would reduce the NO reduction reactions with char. This would result in a higher NO emission. In a related situation, a higher bed temperature would reduce the char concentration in the combustor. This results in a higher NO_x emission at a higher bed temperature as is shown in many studies (19,20,21). Indeed, the higher conversion rate of volatile-nitrogen in the combustor at a higher bed temperature would also contribute to the higher NO emission.

Effect Of Sulfur Content And Retention Requirement

The sulfur content of the fuel and the retention requirement determines the limestone requirement. It has been shown in many studies by Lee et al. (22,23) , Furusawa et al. (11,24) and Leckner et al. (25) that calcined limestones catalyze the conversion of volatile-nitrogen to NO. Therefore, an increase in limestone feed rate or Ca/S ratio would increase the NO emission. This is illustrated in figure 6 which shows the effect of Ca/S on fuel-nitrogen conversion efficiency in a circulating fluidized bed combustor, where the conversion efficiency increases from 9.68 to 11.48% as the Ca/S molar ratio increases from 1.6 to 4.7. These are results from burning a low sulfur coal in the Ahlstrom 1.5 MW pilot plant. The operating conditions were: T = 865 °C, Vg = 5 m/s, Primary air = 65 %, Exit O_2 concentration (wet): 3.6 %.

Similar trends have been obtained by other studies (21,26). Considering the reactivity of the limestone and particle size, a higher reactivity or smaller limestone particle size, but not to elutriable size from cyclone, would reduce limestone consumption requirement. Hence, the NO_x emission would be reduced.

Effect Of Bed Temperature

The effect of bed temperature on the NO emission has been studied extensively and reported to have strong influence on NO emission (19,20,27). In general, higher bed temperature increases NO emission. In the case of a fuel of low reactivity, a higher bed temperature is required to provide better combustion efficiency. This would in turn increase NO emission when burning that low-reactivity fuel. However, in the case of reduced load, where the velocity and bed temperature are both reduced, the combined effect would give rise to a lower NO emission.

Effect Of Excess Air Ratio And PA/SA Split

The availability of oxygen for fuel-nitrogen in the combustor is very important for the conversion to NO. Therefore, a lower excess air ratio would reduce NO emission. Staged combustion which is achieved by splitting the air flow into primary air and secondary air, is used to reduce the oxygen concentration available to the volatile-nitrogen in the lower section of the bed. This reduces the conversion of volatile-nitrogen to NO as well as promoting reduction between volatile-nitrogen and NO formed. A lower primary air to secondary air split would give rise to lower NO emission (20,28). However, the PA/SA split normally would range from 1 to 2.75 because of the need of good fluidization in the lower section of the bed.

ADDITIONAL NO_x CONTROL METHODS

Staged combustion is very effective in reducing NO_x emission from CFBC. However, in places when NO_x emission control is extremely stringent, additional NO_x control measures will be taken in addition to staged combustion. This can be accomplished to a certain extent by flue gas recirculation or injection of ammonia or urea into the cyclone where reduction of NO by NH_3 takes place (28). The efficiency of the ammonia injection method has been demonstrated both in pilot plant and in commercial boiler operation. Figure 7 shows the effectiveness of ammonia injection on NO reduction in AHLSTROM PYROFLOW® boilers as a plot of NO_x reduction % versus NH_3/NO_x molar ratio (28). However, due to the temperature sensitivity of the reaction, under reduced load conditions, the cyclone temperature may not be high enough to give good efficiency for NO_x reduction.

CONCLUSIONS

The conversion efficiency of fuel-nitrogen to NO in CFB as a function of different fuel characteristics and operating conditions have been discussed. Simple correlation between conversion efficiency of fuel-nitrogen to NO and volatile-nitrogen content or volatile content can be obtained. However, there are exceptions which illustrate the complexity of the interactions among different parameters. It is, therefore, necessary to develop a mathematical model to predict NO_x emission from CFB for better understanding of the processes involved. Nevertheless, experimental studies on the overall kinetics of heterogeneous catalytic reactions in the fuel-nitrogen conversion pathways are needed. In addition to staged combustion, other NO_x control measures such as flue gas recirculation and ammonia or urea injection can reduce NO_x further but limitations exist when following load turndown.

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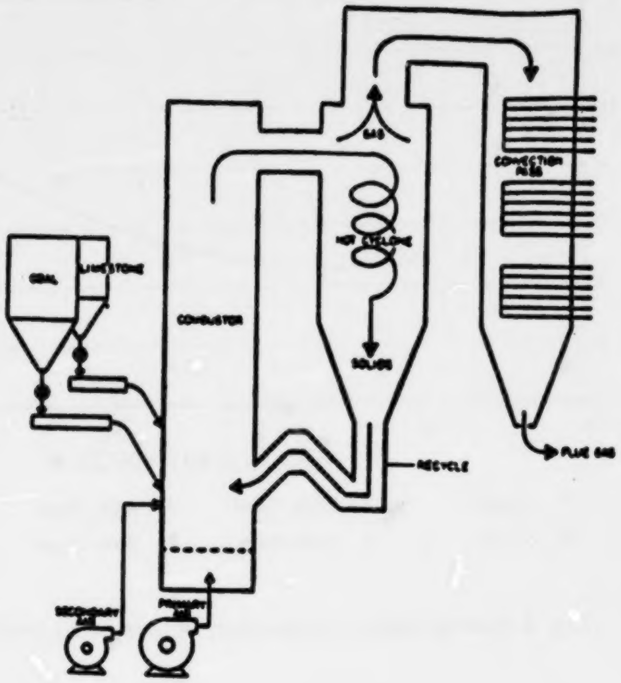
GAS
CONVECTION PASS
HOT CYCLONE
COAL
LIMESTONE
COMBUSTOR
SOLIDS
RECYCLE
FLUE GAS
SECONDARY AIR
PRIMARY AIR

Figure 1: CIRCULATING FLUIDIZED BED BOILER

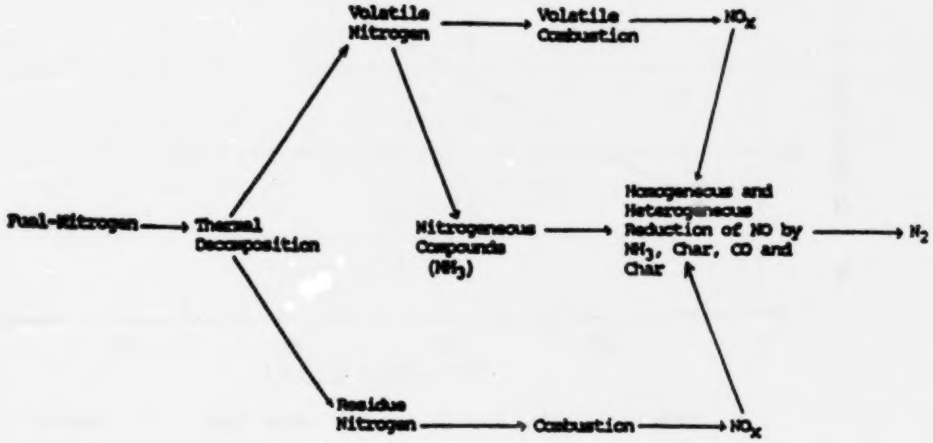
Volatile Nitrogen
Volatile Combustion
NO_x
Fuel-Nitrogen
Thermal Decomposition
Nitrogeneous Compounds (NH_3)
Homogeneous and Heterogeneous Reduction of NO by NH_3, Char, CO and Char
N_2
Residue Nitrogen
Combustion
NO_x

Figure 2: The Fuel-Nitrogen Conversion Pathways in Combustor

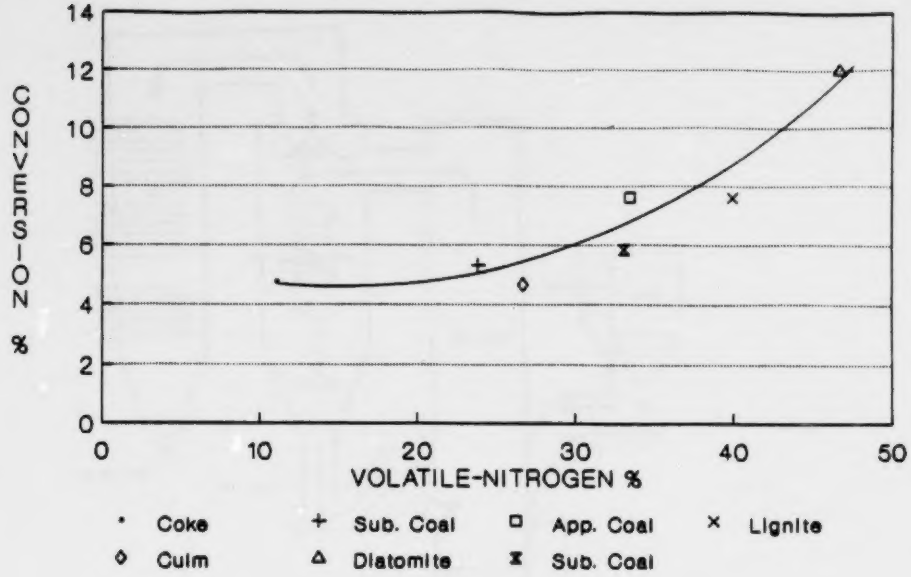

Fig. 3 Fuel-nitrogen conversion versus volatile-nitrogen %

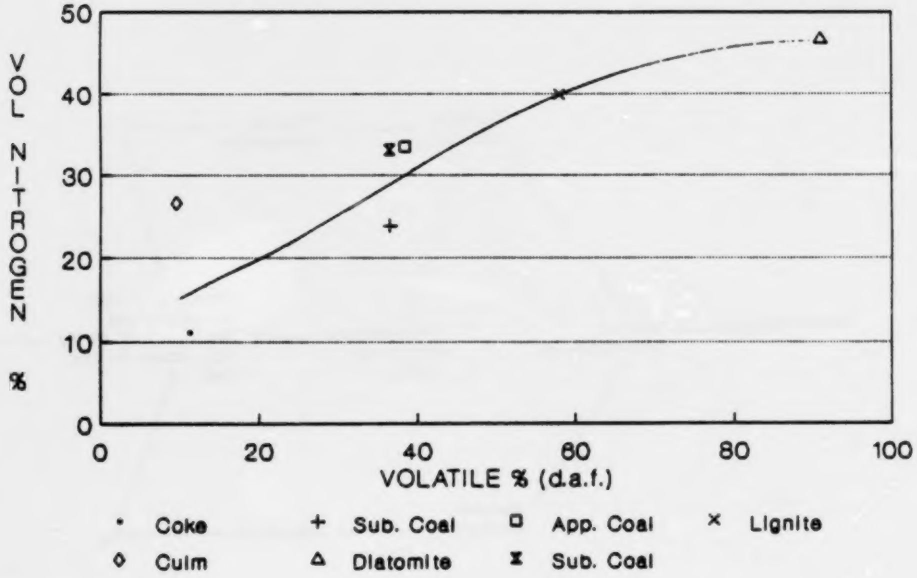

Fig. 4 Volatile-nitrogen % vs. volatile % (daf)

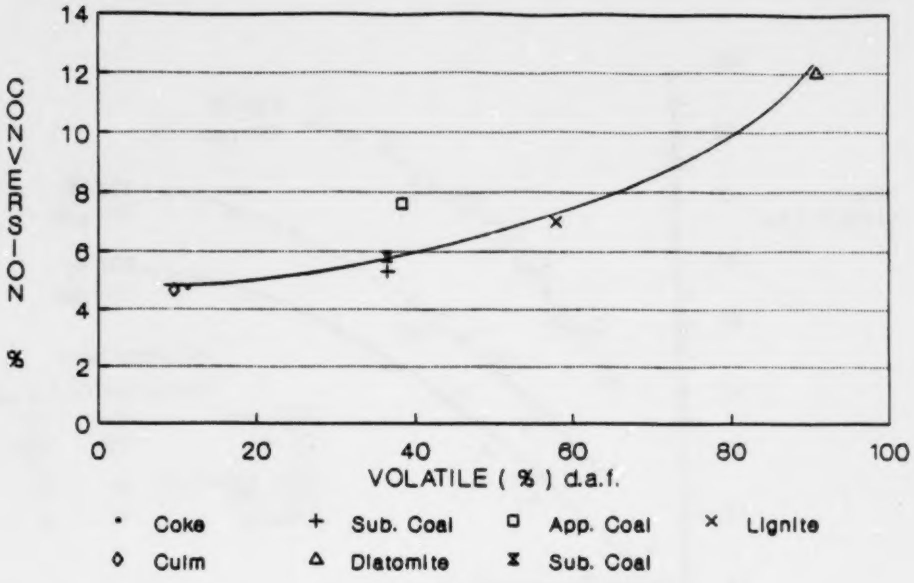

Fig. 5 Fuel-nitrogen conversion to NO versus volatile % daf

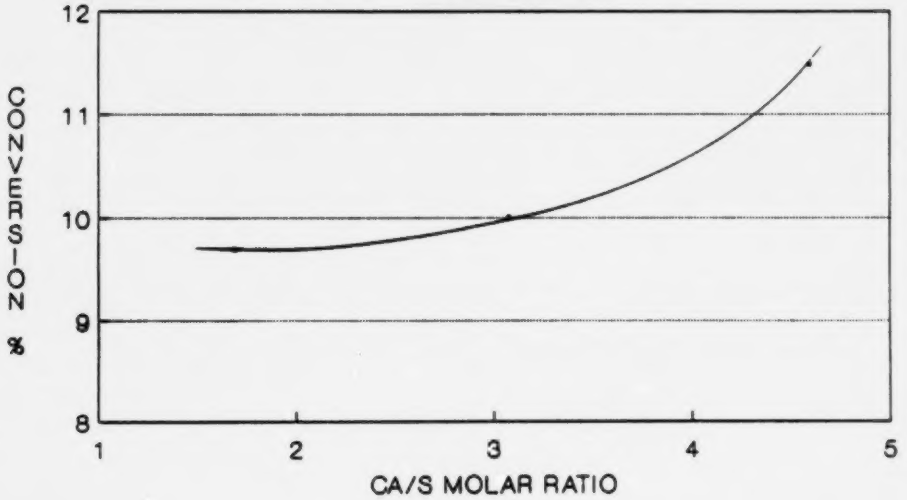

Fig. 6 Effect of Ca/S ratio on fuel-nitrogen conversion

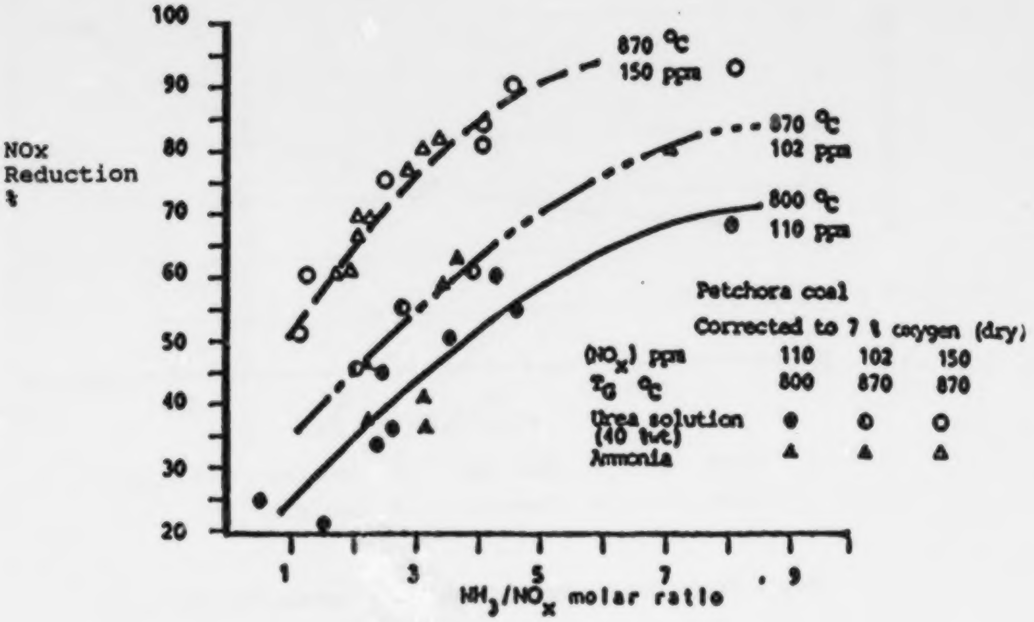

Figure 7: NO$_x$ Reduction In AHLSTROM PYROFLOW With Ammonia or Urea. Base NO$_x$ Level and Temperature at the Injection Location as Parameters

TABLE 1 - IMPORTANT OVERALL REACTIONS IN FUEL-NITROGEN CONVERSION PATHWAYS

REACTIONS	REFERENCES
$4\,NH_3 + 5\,O_2 \xrightarrow{CaO} 4\,NO + 6\,H_2O$	Furusawa et al. (24), Lee et al. (22)
$4\,NH_3 + 5\,O_2 \rightarrow 4\,NO + 6\,H_2O$	Lyon et al.(30), de Soete(29)
$NO + CO \xrightarrow{Char} \frac{1}{2}\,N_2 + CO_2$	Chan et al.(31)
$NO + CO \xrightarrow{CaO} \frac{1}{2}\,N_2 + CO_2$	Tsujimura et al.(32)
$NO + H_2 \xrightarrow{CaO} \frac{1}{2}\,N_2 + H_2O$	Tsujimura et al.(33)
$NO + Char \rightarrow \frac{1}{2}\,N_2 + CO$	Chan et al.(34), Furusawa et al.(35)
$6\,NO + 4\,NH_3 \rightarrow 5\,N_2 + 6\,H_2O$	Lyon et al.(30), de Soete(29)

TABLE 2

FUEL ANALYSIS FOR NO_x STUDIES

FUEL	DIATOMITE	PETROLEUM COKE	APPALACHIAN COAL	PROCESSED CULM	LIGNITE	SUB-BITUMINOUS COAL	SUB-BITUMINOUS COAL
Ash (in dry solids) %	78.0	1.64	13.0	40.2	32	20.6	21.4
C (in dry solids) %	15.3	88.6	74.3	55.2	50.4	63.4	65.9
H (in dry solids) %	2.0	3.9	4.5	1.6	3.18	3.57	4.02
N (in dry solids) %	0.3	1.1	1.0	0.9	1.17	1.03	1.03
S (in dry solids) %	2.6	2.8	1.4	0.45	3.86	1.57	0.6
O (as difference) %	1.8	1.9	5.8	1.65	9.39	9.83	7.05
HHV MJ/kg	7.18	33.5	29.4	19.07	19.	24.4	25.9
Volatiles N %	47.0	11.0	34.0	26.66	39.92	33.04	23.85
Volatiles (daf) %	90.91	11.18	38.39	9.53	57.94	36.4	36.51

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NOx CONTROL IN COAL GASIFICATION COMBINED CYCLE (IGCC) SYSTEMS

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ABSTRACT

NOx emissions at the pioneer 120 MW Cool Water Gasification Combined Cycle plant (located at Southern California Edison's station at Daggett, California) have been measured at 0.047--.090 lb/million Btu of coal fed. This is equivalent to 8-15% of the New Source Performance Standards for coal fired power plants. These low emissions have been obtained on four different coal feedstocks and were achieved simultaneously with low emissions of SO_2 (0.024-0.111 lb/million Btu), particulates (0.01 lb/million Btu) and CO (1-3 ppm).

The Cool Water gas turbine (GE 7000E) has a firing temperature of 1985°F. Separate combustion studies conducted by manufacturers on various medium Btu gases indicate that the new higher firing temperature (2300° F) machines, such as the GE MS 7001F should also be able to meet New Source Performance Standards by an ample margin using similar techniques to those successfully demonstrated at Cool Water. Even lower NOx levels should be obtainable with staged combustion designs that are being developed.

INTRODUCTION

The Acid Rain Issue

Emissions of sulfur dioxide and nitrogen oxides into the atmosphere increase the acidity of moisture in the air, resulting in acid rain. Man made sulfur dioxide and nitrogen oxide emissions in the U.S. are currently estimated at over 40 million tons per year with coal-fired power plants accounting for 55% of the SO_2 released and 27% of the NOx (1).

A Department of Energy (DOE) computer model suggests that sulfur dioxide emissions in the United States could be reduced by as much as 60%[1] by 2010 through the broad commercial use of clean coal technologies. Nitrogen oxide emissions could also be significantly reduced, depending on the technology utilized. According to DOE, Integrated coal Gasification Combined Cycle (IGCC) would provide the best NOx reduction; approximately 23%[1] (2).

There are two sources of NOx when burning fossil fuels. A high proportion of fuel bound nitrogen is converted to NOx during combustion (fuel bound NOx) and some of the nitrogen from the combustion air is converted to NOx at high combustion temperatures (thermal NOx).

A generalized Coal Gasification Combined Cycle system is shown in Figure 1 based on oxygen blowing of the gasifier. With GCC systems utilizing cold gas clean up, the production of fuel bound NOx is avoided since any fuel bound nitrogen components are removed in the gas cooling and sulfur removal sections

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[1] Relative to projected total national emissions in 2010 without clean coal technology.

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prior to the combustion of the syngas. NOx control in such systems must therefore primarily rely on control of thermal NOx production during combustion.

FATE OF COAL BASED NITROGEN DURING GASIFICATION

In coal gasification most of the nitrogen found in the coal is converted to nitrogen gas (N_2) in the gasifier. A small fraction of the coal's nitrogen does form ammonia (NH_3) in the gasifier. The amount of NH_3 depends on the gasification temperature and the chemical equilibrium $2 NH_3 \rightleftharpoons N_2 + 3H_2$.

Higher temperatures result in lower ammonia yields. There are three general types of gasifiers moving bed, fluidized bed, and entrained flow systems. Moving bed gasifiers are countercurrent devices with typical outlet temperatures 800-1200°F. Fluidized bed gasifiers operate at 1500-1900°F and Entrained flow gasifiers typically operate in the range 2300-2800°F. The percentage of coal based nitrogen that is converted to NH_3 is 50-60% with moving beds but typically only 10-15% with entrained flow gasifiers.

In IGCC systems with cold gas clean up the ammonia is easily removed from the syngas by condensation and water quenching in the gas cooling train prior to the acid gas (H_2S) removal (see Figure 2). This condensate is then steam stripped and the overhead fed to the Claus plant where the ammonia is converted to harmless elemental nitrogen N_2. Small traces of hydrogen cyanide are also typically present in the raw gas which are similarly quenched, condensed, stripped and converted to elemental nitrogen in the Claus plant.

The US Department of Energy (DOE) has sponsored a considerable amount of work on the development of air blown hot gas clean up GCC systems. In this kind of system the control of fuel bound NOx is an additional issue which needs to be addressed due to the presence of NH_3 in the gas going to the gas turbine.

EFFECT OF COAL GAS COMPOSITION ON THERMAL NOx

The gas compositions for various gasification processes are shown in Table 1. Thermal NOx is primarily related to fuel gas flame temperature. The adiabatic stoichiometric undisassociated flame temperatures of various gases are shown in Table 2. Further discussion of the various effects of gas properties on gas turbine design have been described in an excellent earlier paper available from the General Electric Company (Reference 3). An estimate of the effect of flame temperature on NOx emissions is also shown in Table 2. (taken from Ref. 3)

Coal derived gas fuels are mixtures of hydrogen and carbon monoxide. Methane may be present in the gas from some gasifiers (e.g., BGL and KRW) while carbon dioxide, nitrogen or water are diluents. For most coal gases considered the ratio of CO to H_2 is of only minor consequence with regard to flame temperature, however the effect of diluents is of paramount importance in controlling both flame temperature and NOx. Most generally considered indices of combustor performance worsen as volumetric heating value decreases: Fuel/Air ratio increases, the amount of fuel to achieve a given temperature rise increases and residence time in the reaction zone decreases. There is obviously some limitation on the amount of diluent that can be added without some sacrifice of combustion efficiency (CO-burnout) or eventual actual loss of flame. However, the presence of hydrogen (with its high flame speed) in coal derived gases appears to provide an early ignition and completion of combustion so that low NOx and low CO can be simultaneously achieved, at least over the range of medium Btu gas compositions derived from the major candidate coal gasification processes. Of the three major diluents, CO_2, H_2O and N_2, CO_2 has a greater effect in reduction of flame temperature for a given degradation in heating value. The Texaco/Dow gases and Shell/BGL gases present different challenges to the gas turbine combustor designer. The Shell/BGL gases have lower inerts content and therefore flame temperatures >100°F higher than Texaco/Dow gases. However, NOx control can be achieved by adding diluents to the fuel. Generally, H_2O is a better choice than N_2 unless high pressure N_2 is available which will not be used elsewhere in the cycle. (Ref. 4, 6)

In the highly integrated IGCC configuration described by GKT and Siemens KWU, air is extracted from the gas turbine compressor to feed a higher than usual pressure Air Separation Unit (ASU). Approximately 85% oxygen is fed to the gasifier and the pressurized N_2 from the ASU is further compressed and fed to the gas turbine combustor, thereby assisting in NOx control by dilution of the fuel gas. (Ref. 7)

Extensive combustion development tests have been conducted in single advanced burner test stands installed in General Electric's Gas Turbine test facility in Schenectady, N.Y. (Ref. 4) Various medium gas compositions representative of gases derived from the major candidate coal gasification processes were provided from high pressure tube trailers. NOx measurements showed that addition of diluents can be used to achieve NOx standards with advanced high temperature gas turbines (such as the MS7001F) well within NSPS limits for coal fired plants. Further combustor modifications and if necessary post combustion De-NOx techniques such as SCR should be able to achieve extremely low NOx (<5 ppm at 15% O_2).

PROGRAM DESCRIPTION

Cool Water Coal Gasification Program

The Cool Water Coal Gasification Program has proven that the integration of coal gasification with combined cycle power production is commercially viable and environmentally superior to conventional coal-fired power plants. The plant has successfully demonstrated the IGCC technology on four difference bituminous coals: SUFCo, a low-sulfur coal form Utah; Illinois No. 6, a high sulfur coal form Illinois; Pittsburgh No. 8, a high sulfur coal from West Virginia; and Lemington, a low sulfur, high ash fusion temperature coal from Australia. Although the Lemington was a foreign coal, tested for the Program's Japanese partners, the run showed that the technology has the ability to utilize the large reserves of high ash fusion temperature bituminous coals present in the United States in an environmentally acceptable manner.

The Program's participants (equity owners) are Texaco Inc., Southern California Edison Company, the Electric Power Research Institute, Bechtel Power Corporation, General Electric Company and the Japan Cool Water Program Partnership. The Empire State Electric Energy Research Corporation and SOHIO Alternate Energy Development Company were contributors to the project.

Process Description

Cool Water is a nominal 120-MW IGCC power plant that uses the Texaco Coal Gasification Process to produce a medium-Btu fuel gas. A block flow diagram of the facility is presented on Figure 2. The gas is combusted in the combined cycle portion of the plant to produce electricity. The plant was designed to process up to 1000 tons of coal per day mixed with water, however, rates as high as 1200 tons per day have been achieved. The coal-water slurry is gasified with oxygen at a pressure of approximately 600 psig and temperature between 2100 F and 2500 F. The raw syngas from the gasifier is first cooled in radiant and convective coolers that generate steam for use in power production. The slag solidifies during its fall through the radiant cooler and collects in a water sump at the bottom of the cooler, where it is removed periodically using a lockhopper system. After leaving the radiant and convective syngas exchangers, the cooled synthesis gas enters a water scrubber, low level heat is recovered from the gas in a series of exchangers, followed by air and cooling water trim cooling until the gas is approximately 100 F. Sulfur is removed, primarily in the form of hydrogen sulfide, in a Selexol absorber. A sulfur-rich acid gas is stripped from the Selexol solution and routed through a SCOT/Claus sulfur recovery unit to produce an elemental sulfur product. Following sulfur removal, the gas is reheated and partially resaturated utilizing hot water available from the raw gas cool down. This arrangement enhances overall system heat recovery while providing water vapor to the gas for NOx control. Live steam injection is also available to supplement the moisture added by saturation. The synthesis gas is fired in a GE model 7000E combustion turbine to produce electricity. The heat from the gas turbine exhaust is utilized in the heat recovery steam generator (HRSG): to generate high pressure saturated steam; to superheat the steam generated in the HRSG, in addition to the steam from the syngas cooler; and to provide boiler feedwater heating for both the HRSG and syngas cooler. The cooled gases are then discharged to the atmosphere through the HRSG stack. Carbon monoxide, NOx, sulfur dioxide, and carbon dioxide are continuously monitored in the exhaust flow from the HRSG stack. The first three compounds are monitored per guidelines of the EPA and the San Bernardino County Air Pollution Control District (SBCAPCD).

NOx Emissions at Cool Water

Cool Water has easily met EPA New Source Performance Standards (NSPS) for NOx on all of the coals tested. As shown in Table 1, EPA test results for NOx ranged from 0.047 to 0.090 lb/million Btu coal, compared to a NSPS limit of 0.60 lb/million Btu. Federal requirements for SO_2, CO, and particulates were also met by a wide margin, also shown in Table 3.

Emission Limits

Emissions from the plant are limited by Federal, regional, and local regulations. National emission limits for coal burning plans were stated in the New Source Performance Standards (NSPS), enacted in 1979 by the U.S. Environmental Protection Agency (EPA). Emissions from CWCGP have been well below these standards, generally 8-15% of these limits. The permit granted by EPA Region IX in 1981, prior to plant construction, imposed stringent limits based on design estimates, and the initial operation at CWCGP demonstrated the ability to meet those limits. Local permits received in early 1988 from the San Bernardino County Air Pollution Control District (SBCAPCD) set more stringent NOx limitations. The actual range of values demonstrated during operations was within each emission limit in this permit. Compliance with all regulations has been maintained through careful plant operation.

The various regulations have emission limits with differing bases and units. The NSPS rules are in terms of percent removal and pounds per million Btu of coal (lb/MMBtu). The EPA and SBCAPCD permits contain limits in combinations of pounds per hour and concentration (ppmv dry). The SBCAPCD limit for HRSG NOx emissions is 80 ppmv corrected to 3% exhaust oxygen; which for a gas turbine with 15% oxygen in the exhaust is the equivalent of 26 ppmv NOx at stack conditions. Table 1 shows all of the permit limits converted to a lb/MMBtu basis. For each parameter, the SBCAPCD limits are the most stringent (5).

NOx Control

Cool Water has been able to consistently achieve low levels of NOx for two reasons: (1) No ammonia or organic nitrogen compounds are present in the fuel gas to form NOx from fuel bound nitrogen, and (2) thermal NOx formation is held to very low levels by syngas saturation and steam injection.

With most commercial gas turbine combustors, fuel bound nitrogen is converted almost entirely to NOx during burning.[2] In IGCC systems utilizing cold gas cleanup, the production of NOx from fuel bound nitrogen is avoided. The majority of the nitrogen in the coal is converted to harmless nitrogen gas (N_2) in the gasifier. A small fraction of the coal's nitrogen does form ammonia in the gasifier, but this source of fuel bound nitrogen is removed in the gas cooling and sulfur removal sections before the syngas is combusted. The ammonia is routed with the sulfur bearing gases to the sulfur recovery unit where it is converted to N_2. Therefore, an IGCC power plant like Cool Water must deal only with thermal NOx formation.

Thermal NOx production is directly related to a fuel's flame temperature, all other influences being equal. Cool Water lowers NOx production rates below the level that would be achieved by burning dry synthesis gas through the use of syngas saturation and steam injection. By adding a diluent, water vapor, the reaction zone temperature in the combustor is lowered, reducing NOx production. The effect of moisture addition on NOx formation is shown on Figure 3. The dry NOx level of 63 ppmv is reduced to 12 ppmv by syngas saturation. Gas turbines are limited in the amount of water or steam that can be injected because: (1) the fire will blow out at some point, (2) prior to the loss of flame, carbon monoxide emissions will increase and combustion efficiency will decrease, and (3) combustion components' lives may be decreased by pressure oscillations or noise generated by the combustion process (4). Cool Water has never experienced a flameout, even at steam to gas addition ratios as high as 0.38 lb steam/lb dry gas; where NOx was only 12 ppmv. Carbon monoxide formation was still very low at this level of saturation; 2 ppmv as shown in Figure 3. The monitoring equipment on the combustion turbine showed no change in normal vibrations that would have indicated increasing pressure oscillations or noise from the moisture addition. These results were very encouraging for future IGCC plants because similarly high levels of syngas saturation and/or steam injection will be needed to achieve low NOx levels in the new higher firing temperature gas turbines, such as the GE MS7001F.

It is also of interest to contrast the medium Btu gas (MBtu) data shown in Figure 3 with the performance data on natural gas for a typical 7000E combustor. The dry NOx level is about 140 ppmv which can be reduced to about 40 ppmv with a steam/fuel mass flow ratio of about 1/1 (Ref. 5, Fig. 1&3). However, this amount of steam dilution would also result in about 40 ppmv CO (Ref 5, Fig. 1&3). Furthermore if more steam was added to reduce the NOx with natural gas to about 25 ppmv then the corresponding CO would be >200 ppmv. As mentioned before in this paper the ability to obtain low NOx (10-20 ppmv) with MBG fuel is attributable to the hydrogen present in the MBG fuel. It should also be mentioned General Electric has recently developed a "quiet combustor" or dry low NOx combustor capable of meeting 25 ppmv NOx at 15% O_2 in MS7001EA fired with natural gas (Ref. 6). Furthermore, the CO emissions can be reduced by a fairly low cost post combustion catalytic conversion in the HRSG.

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[2] To date, combustion systems have been developed and field-demonstrated for fuels that do not contain significant bound nitrogen. A fundamentally different kind of combustor (i.e., staged rich-quick quench-lean) is necessary when there is significant bound nitrogen in the fuel.(4)

The Texaco gasifier produces a medium Btu gaseous fuel having a higher heating value of approximately 265 Btu/SCF. The composition of the synthesis gas at Cool water, following particulate and sulfur removal, on each of the test coals are set forth in Table 4.

Changes in gasification section operating parameters can alter the composition of the gas and subsequently the amount of NOx formation, assuming all other factors are constant. During operation at high slurry concentration the plant observed an increase in NOx production. (Ref. 4) The increase in NOx was expected because operation at high slurry concentration reduces the concentration of CO_2, a diluent, and an increase in flame temperature results. Similarly, reducing the temperature of the gasifier will lower the CO_2 content of the syngas and raise the NOx production. Adjustments in saturation and steam injection have allowed the plant to meet NOx permit criteria at all normal gasifier operating conditions. The data from this testing is plotted in Figure 4. Notice that the data points for high slurry concentration show higher levels of NOx formation at a given steam to gas mass ratio than the points for normal slurry concentration.

Figure 4 also shows the effect of reduced load on NOx formation. The trend line representing 90% load indicates a 8-10 ppmv lower NOx than full load. The two 65% points show NOx production continuing to drop as load is reduced. The lower NOx at reduced load is a result of a leaner mixture causing lower temperatures in the combustor.

In Figure 4, carbon monoxide values are also plotted against steam to gas ratio. CO is below 4 ppmv at all test conditions except the 65% load points, where it rises to 6-7 ppmv. The small increase is probably a result of slightly reduced combustion efficiency at high turndown.

Using the same data, NOx is plotted against fuel lower heating value (wet basis) in Figure 5. The high slurry concentration points new fall along the same trend line as the fuel load points which indicates, for the operating range covered by this data, the turbine NOx production rate at full load is a function of the fuel's heating value.

N_2O Testing at Cool Water

Nitrous oxide (N_2O) is one of the molecules believed to contribute to the greenhouse effect. Because of increased concern on global warming, the exhaust of the Cool Water combustion turbine was tested for N_2O during 1988. The analytical work, performed with the gas turbine operating at base load, showed that the exhaust levels of nitrous oxide were very low, less than 0.5 ppmv. Two separate analytical methods were utilized. In the first a flask sample is taken conditioned and analysed by gas chromatography. In the past this method has given widely differing results depending on the gas conditioning techniques used. Recently a new technique using Non-Dispersive Infra Red (NDIR) spectrometry has been developed at the University of California at Irvine under EPRI sponsorship for on-line measurement. The results from each of these methods showed N_2O only at about the limits of detection.

Combustor Modifications for NOx Control

The application of fuel saturation and/or combustor steam injection to further lower NOx emissions in not unlimited. In order to reach levels below 10 ppm, especially with the new higher turbine firing temperatures (2300°F) combustion turbines now being introduced, new combustor designs will likely have to be developed. New dry-low NOx combustors are currently being planned for these turbines when burning natural gas fuel. These combustors are designed to allow less than 25 ppm NOx without any steam or water injection. Besides simplifying the plumbing and allowing simple cycle operation without a water supply these combustors result in a somewhat higher combined cycle efficiency. This is because the steam that would have been injected (or mixed with the fuel) for NOx control can now instead be expanded in the steam turbine down to high vacuum which provides more power than would its expansion in the gas turbine down only to (approximately) atmospheric pressure.

The new dry-low NOx combustors are based on staged combustion and premixing concepts that keep the fuel-air mixtures as far as possible from the stoichiometric ratio that produces the highest flame temperature. The NOx formation rate due to fixing of the air nitrogen by the Zeldovitch Mechanism goes up exponentially with the flame temperature. The most common new dry-low NOx combustor designs work at the engine full power point with premix of the natural gas fuel and air in a lean mixture and then combustion, followed by air dilution to lower the combustion products to the desired combustor exit temperature. For starting and partial power, however, premixing is not feasible and the combustors are designed for staged zones of lean diffusion flames; starting with one zone and bringing on the second as more power is desired.

Some medium Btu syngas containing mainly CO and H_2 as combustibles (e.g., Shell and BGL) have a stoichiometric flame temperature about 100°F higher than natural gas (methane). Thus it is even more important to combust lean away from the stoichiometric condition. However, premixing is considered impractical with syngas due to the presence of H_2 in the fuel, since the high flame speed of the H_2 would tend to cause flashback in the premixing zone. The proposed practical arrangement would be a staged lean-lean combustor with diffusion flames in both zones. The use of fuel saturation or steam injection in conjunction with this lean-lean design would have the promise of bringing NOx emissions to below 10 ppm without excessive CO formation for syngas fuel.

Leaning out the flame or adding diluents such as water/steam or CO_2 is limited by lack of flame stability and poor combustion efficiency which produces excessive CO. This basic limit in combustion design and operation seems to be much less limiting with synfuel than with methane or distillate. The Cool Water results showing very low CO formation at low NOx levels strongly support this conclusion. The basic reason appears to be that the H_2 in the fuel with its high flame speed stabilizes the combustion even at very low flame temperature. This is the basis of the expectation that lean-lean staged combustor can be operated with syngas in a lean enough manner and even with some steam injection to produce very low <10 ppm NOx emission with high combustion efficiency.

NOx can also be formed from fuel nitrogen compounds. This direct NOx formation is not a strong function of flame temperature and cannot be supressed by lean combustion. Fortunately gases from oxygen blown cold clean-up medium Btu gasification processes do not contain significant amounts of these compounds. However, fuel bound nitrogen will exist in air blown low Btu syngases with hot gas clean-up. Combustors with rich-quick quench-lean designs have been partially developed that show promise of limiting the direct NOx formation. They work on the principle that in the rich zone the nitrogen compounds are starved for O_2 and in the flame react back to N_2. Combustion then proceeds in the lean zone at a low enough temperature to limit Zeldovitch NOx formation. The rich-quick quench-lean combustor is applicable to all fuels. However, it is not as fully developed nor does it appear to give as low NOx levels as the lean-lean combustor for fuels without nitrogen compounds.

Post Combustion NOx Control (SCR)

The emissions can be further lowered significantly, typically about 90%, by engine exhaust clean-up with selective catalytic reactors SCR's. Many installations of SCR's have been made for NOx reduction of natural gas fired turbines in combined cycle applications. The SCR is installed in the HRSG in the region where the flue gas temperature is between 550 and 750°F. Ammonia gas NH_3 in about the same molar flow as the NOx is introduced. The NOx is reduced to N_2 by flowing over the catalyst (usually vanadium pentoxide). Large amounts of catalyst coated structure are required, about 50 cu. ft. per MW. The catalyst is sensitive to sulfur and cannot be used with fuels containing more than about .1% sulfur. All of the syngas systems under consideration meet this criteria. It is virtually certain that a syngas system would only be used with a combined or other heat recovery cycle, such as the steam injected gas turbine, rather than the simple cycle. Thus the 590°-750°F flue temperature requirement would easily be met. While as yet there has been no significant test on synfuels with SCR, there is every expectation that in conjunction with the advanced lean-lean combustor and fuel saturation, the application of SCR would reduce NOx level to below 5 ppm. This would be at the extra cost, both capital and maintenance of the SCR. The capital cost may be less significant for the IGCC if its dispatch factor is high compared to natural gas fueled combined cycles. Conversely, any time required to replace or maintain the SCR catalyst would impact more on the IGCC.

There are also flue gas CO removal catalytic oxidation systems these are not temperature sensitive and not as costly as the SCR NOx removal system. Their drawback, besides the extra cost, is the additional pressure drop they cause. This would lower the power level and efficiency (as does the SCR system) by about 0.5-1.0%. The CO formation itself is a sensitive indication of poorer combustion efficiency and thus the heat rate. However, the available use of the CO catalytic system would allow the application of lean-lean combustors with steam injection or fuel saturation for very low NOx emission that might otherwise be restricted because of excessive CO emissions.

Conclusion

NOx emission at Cool Water have been measured at levels only 8-15% of those required to meet NSPS for coal fired plants. Actual combustion tests have also been conducted by gas turbine manufacturers on various medium Btu gases which indicate that GCC systems based on the advanced gas turbines with higher firing temperatures should also be able to surpass NSPS by ample margins using similar diluent techniques to those applied at Cool Water. Should still lower NOx levels be required these should be obtainable by staged combustion designs now under development. Extremely low levels (e.g., <5 ppm) would probably require use of the rather cumbersome post combustion treatments such as Selective Catalytic Reduction (SCR).

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TABLE 1

GAS COMPOSITIONS FROM VARIOUS COAL GASIFICATION PROCESSES

Clean Dry Basis - Volume Percent

	Texaco	Dow	Shell	BGL	KRW (O_2)	KRW (air)
CH_4	--	--	--	7	7	2
H_2	36	41	31	29	34	12
CO	47	38	62	60	45	21
CO_2	16	19	2	3	11	13
N_2, etc.	1	1	5	1	3	52

TABLE 2

GAS PROPERTIES AND RELATIVE NOx EMISSIONS(1)

Gas	LHV Btu/SCF	Flame (2) Temperature °F	Thermal Relative NOx(3)
Methane	911	3982	1.00
Carbon Monoxide	321	4536	3.42
Hydrogen	274	4311	2.07
Coal Derived Low Btu Gas	~110	~2850	0.07

TABLE 3

HRSG ATMOSPHERIC EMISSIONS
(lb/million Btu coal)

EPA Test Results	Federal NSPS*	Local Permit SBCAPCD **	
NO_x			
Utah coal	0.056	0.60	0.07
Illinois No. 6 coal	0.090	0.60	0.07
Pittsburgh No. 8 coal	0.060	0.60	0.07
SO_2			
Utah coal (.35% sulfur)	0.024	0.17	0.033
Illinois No. 6 coal (3.1% sulfur)	0.064	0.60	0.167
Pittsburgh No. 8 coal (2.7% sulfur)	0.111	0.60	0.167
Lemington coal (.45% sulfur)	0.027	0.22	0.033
CO			
Utah coal	0.002	.073***	0.015
Illinois No. 6 coal	0.003	.073***	0.015
Pittsburgh No. 8 coal	0.002	.073***	0.015
Lemington coal	0.001	.073***	0.015
Particulates			
Utah coal	0.011	.03	0.011
Illinois No. 6 coal	0.008	.03	0.011
Pittsburgh No. 8 coal	0.009	.03	0.011
Lemington coal	0.011	.03	0.011

* New Source Performance Standards for coal fired power plants.

** Local permit limitations, received in early 1988 from the San Bernardino County Air Pollution Control District (SBCAPCD). The Illinois No. 6 and Pittsburgh No. 8 coals were tested in early 1986 so the local emissions limits were not in effect when these coals were tested. If the Illinois No. 6 or Pittsburgh No. 8 coals were run again at Cool Water, the SBCAPCD requirements for NOx could be easily met by using additional steam injection or syngas saturation.

Table 4

Clean Syngas Composition and Heating Value for Each Test Coal Fired at Cool Water

	SUFCo	Illinois No. 6	Pittsburgh No. 8	Lemington
Clean Dry Composition (vol%)				
Carbon Monoxide	43.0	44.8	44.3	44.2
Hydrogen (H_2)	38.1	38.4	39.4	36.9
Carbon Dioxide	18.1	15.5	15.5	18.0
Methane	0.2	0.2	0.2	0.1
Nitrogen (N_2), argon				
Btu/SCF	264	271	272	262

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DEVELOPMENT OF NO_x CONTROL TECHNOLOGIES FOR COAL-FUELED STATIONARY DIESEL POWER PLANTS

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ABSTRACT

Coal-fueled stationary diesel engines are being developed to provide electric power and by-product steam in the size range of 2 to 50 MWe. Such engines will be commercially viable if the cost of cleaned coal is low relative to diesel fuel, if engine wear can be minimized, and if cost-effective emission control technologies can be applied. The emission of primary concern is NO_x.

The paper summarizes NO_x emission measurements from a 13-in. bore, 400 rpm, single-cylinder test engine modified to fire ultra-clean coal-water fuel. Uncontrolled emissions are a strong function of manifold air temperature (MAT); at a nominal MAT of 250°F, the uncontrolled NO_x emission is about 2.8 lb/mm Btu.

The paper also addresses on-going research to reduce NO_x emissions to 0.6 lb/mm Btu. Control techniques tested include reburning downstream of the engine and selective catalytic reduction using low-cost catalyst. Preliminary NO_x control experiments are presented and discussed.

BACKGROUND

Arthur D. Little, Inc. is leading a team of subcontractors in a DOE-sponsored program to develop diesel-powered cogeneration systems using our most plentiful and least costly indigenous fossil fuel: coal. A key subsystem of such a plant will be the emission control equipment. The PSI Technology Company is responsible for evaluating, developing, and designing equipment capable of meeting today's EPA New Source Performance Standards for coal-fired stationary sources. Emissions of primary concern are nitrogen oxides, sulfur dioxide, and particulate matter. Integration of processes to control these emissions while maintaining cycle efficiency and minimizing capital investment and operating costs is the goal of our work.

The program is divided into three phases. In the first phase, we have completed conceptual designs for several candidate NO_x control technologies. Since these technologies have rarely, if ever, been applied to stationary engines, these designs have drawn heavily upon utility and industrial boiler experience to develop general arrangement drawings, material lists, and costs. The results of the design study allowed us to select and prioritize attractive technologies and to direct initial research toward key technical issues that may impact the potential application of each technology to diesel systems.

Laboratory-scale testing of selected NO_x-control processes is now underway. The results of these tests will be integrated into a final emission-control subsystem design which is the final output of the Phase I effort.

In Phase II, the NO_x control equipment selected and designed in Phase I will be built and tested on a Cooper-Bessemer six-cylinder test engine located at Cooper's research facility in Mt. Vernon, Ohio. If successful, an integrated engine system, including optimized fuel, engine, emission control and heat recovery subsystems will be demonstrated in Phase III.

UNCONTROLLED NO_x EMISSIONS

JS-1 Engine

Testing to date has been performed at Cooper Bessemer in a JS-1 research engine. This engine has a 13-in. bore, a 16-in. stroke, and operates in the speed range of 300 to 450 rpm. For the tests reported herein, the engine rpm was held constant at 400 and the engine load was a nominal 150 psi. This engine has been described previously; (1,2) so this discussion will be limited to the engine features that may influence NO_x emissions.

A cross section of the cylinder head is shown on Figure 1. The coal-water fuel injector is mounted in the center of the cylinder. There are two other openings which can be fitted with a diesel pilot injector, a jet cell natural gas ignition, or optical diagnostic equipment. In the tests reported, diesel fuel was used as a pilot fuel, although autoignition of the coal-water fuel was possible for air temperatures greater than 250°F. The pilot fuel flow amounted to 7 to 16 percent of the total heat input to the cylinder.

A conventional cam-driven jerk pump delivered the coal-water fuel to the injector. This allowed injection pressure to be varied independent of total fuel flow. A separately driven compressor supplies combustion air to the engine, with heat exchangers to vary the manifold air temperature from 80° to 430°F independent of pressure or airflow. It will be seen that injection pressure and manifold air temperature were the key variables influencing NO_x emissions.

The coal-water fuel burned during these tests consisted of 52 percent dry coal, 2 percent additives, and 46 percent water. The fuel had mean particle size of 11 microns and a topsize of about 74 microns. The higher heating value of the as-fired fuel was about 7550 Btu/lb and the fuel viscosity at 100°F ranged from 180 to 210 centipoise for a shear rate of 100 to 1000 s^{-1}. Fuel-bound nitrogen, which could contribute to the NO_x emission, was 1.6 to 1.8 wt% on a dry basis.

NO_x Emission Results

In order to compare NO_x levels from different tests, the NO_x data must be converted to a common basis. The NO_x concentration of the gas was measured on a wet basis, while the CO_2 and O_2 levels are given for a dry gas. Therefore, for each experimental point, the amount of H_2O in the gas was calculated based on the ultimate analysis of the fuels. Given a value for the H_2O content, the O_2 content of the exhaust gas on a wet basis can be calculated. The NO_x level in the exhaust gas was then corrected to conditions of 15 percent oxygen.

Table 1 compares NO_x emissions for the JS-1 engine operating at elevated manifold air temperatures during consecutive tests firing diesel fuel and coal-water fuel. In general, the NO_x emissions were similar for each fuel, although considerable day-to-day variability could occur. We speculate that any decrease in the thermal NO_x formation brought about by quenching peak flame temperature when firing CWF is approximately balanced by the production of NO_x from nitrogen bound in the coal. (Diesel fuel contains negligible amounts of fuel-bound nitrogen.) However, it is expected that the conversion of fuel nitrogen to NO_x will be affected by the rate of coal devolitilization, which will depend on the size of the droplets produced during atomization. Atomization changed throughout the test program as injector design and injection pressure was varied, and as the injector nozzle wore away due to the abrasive effect of the coal-water fuel.

NO_x emissions were sensitive to both peak injection pressure and manifold air temperature. Figure 2 shows the NO_x concentration as a function of peak injection pressure for several different values of the intake manifold air temperature. The NO_x concentration that has been used in the preliminary design of the emission control system (900 ppm at 11% O_2) is indicated on the figure. The NO_x concentration in the exhaust shows a general trend of increasing with peak injection pressure.

In Figure 3, data for a narrow range of injection pressures (8,700 to 10,000 psi) are shown as a function of intake manifold temperature. As expected, NO_x concentration in the exhaust increases with increasing manifold air temperature. At air temperatures greater than 300°F, the effect on NO_x emissions is more pronounced.

NO_x CONTROL TECHNOLOGIES

It can be seen from the above discussion that uncontrolled NO_x emissions from coal-fired diesel power systems are likely to be considerably higher than other stationary sources. Although the U.S. Environmental Protection Agency has not promulgated New Source Performance Standards covering this technology, we have examined control technologies (or combinations of technologies) capable of reducing NO_x by 80 percent; i.e., from 2.8 to 0.6 lb/mmBtu. Modifications to engine design and/or operation to minimize baseline NO_x have not been tested to date. Other than using a two-chamber engine to achieve rich-lean combustion, any engine modification that decreases combination temperature or rate of fuel-air mixing is expected to also adversely affect engine efficiency. Therefore, we are limiting our study to post-combustion NO_x control technologies.

At this point, we have completed preliminary designs and cost estimates for the emission control technologies listed in Table 2. The NO_x control technologies are discussed below.

Selective Reduction

In selective reduction, a nitrogen-containing compound (typically ammonia, although urea has also been used) is added to the exhaust gas stream where it reacts with oxides of nitrogen to form N_2. Depending on whether a catalyst is employed the process is called Selective Non-Catalytic Reduction (SNR) or Selective Catalytic Reduction (SCR). The SNR reactions occur in a narrow temperature window (1600° to 2000°F). Since the maximum exhaust temperature expected from a coal-fueled diesel engine is about 900°F, any SNR processes are not applicable.

SCR processes employ a catalyst to allow the NO_x to react with the nitrogenous reducing agent at even lower temperatures (300° to 750°F). Commercial applications on utility boilers employ a variety of catalysts (platinum, vanadium, copper sulfate, zeolite) coated onto a less expensive substrate and arranged as a honeycomb or parallel plate to maximize exposure of catalyst surface per unit of reactor volume.

The major potential operating problems when applying SCR to coal-fueled diesel engines are degradation of catalyst performance due to fouling with engine particulate, ammonia slip, and deposition of ammonium sulfate onto downstream heat transfer surfaces. These problems appear tractable, but the solutions could be expensive. Control of ammonia slip requires a sophisticated NO_x and/or NH_3 monitoring system to assure that the NH_3/NO_x stoichiometric ratio always remains less than unity. Catalyst supports must be open or accessible to soot blowers to prevent pluggage or catalyst blinding by the very fine, carbonaceous flyash produced by the coal-fueled diesel. Vendors contacted to date estimate a 2 to 3 year catalyst life under base-loaded operation.

In order to assess whether the NO_x reduction requirements of the emission control system can be met with a less expensive SCR process, two alternative technologies are being considered. The first alternate SCR process involves using the carbon-containing particulate matter from the engine exhaust as a "free" catalyst. The second involves an iron oxide catalyst and non-ammonia reducing agents that may be more reactive with NO_x.

Recently, the catalytic activity of coke and carbon-containing particulate matter from utility boilers has been demonstrated on a laboratory scale. (3,4) Using coke activated with sulfuric acid, a 70 percent reduction of NO by ammonia at 300°F has been demonstrated. (3) Particulate matter from industrial boilers containing 2 to

30 percent carbon by weight has been used as a catalyst for reduction of NO with ammonia. (4) In the temperature range 570° to 750°F, NO reductions from 40 to 60 percent have been demonstrated. Because of the low ash content of the processed coal used in the engine, the particulate matter contains a very large amount of carbon. The carbon content of the ash was measured to be 80 percent at 98 percent burnout and we calculate 67 percent carbon if combustion efficiency is improved to 99 percent burnout, based on a mass balance using 0.5 percent as the ash content. Thus, it may be possible to exploit the ash as a reduction catalyst. This process will be studied further by conducting laboratory-scale feasibility experiments. Other reducing experts and catalysts for SCR are being pursued in separate experimental programs at PSIT funded by the EPA and Air Force under the government Small Business Innovative Research program.

Reburning

In the reburning process, NO_x is reduced to N_2 as the exhaust gas from the primary combustion process passes through a secondary combustion zone. In boiler applications, fuel-rich reburning conditions allow NO to react with hydrocarbon radials to form CN/HCN. The kinetic path to N_2 is complex, as shown on Figure 4. H and OH radicals are required to convert CN species to NH_i species (i=0,1,2). N or NH_2 reacts rapidly with NO to form N_2; this reaction is favored at lower temperatures, while free radical formation is favored by higher temperatures. Since free radicals are also formed upon the injection of burnout air downstream of the reburn zone, further NO_x reduction or minimal NO_x reformation can be achieved through the design and location of the burnout air injectors. (5)

Application of reburning to stationary diesel power plants is different from boilers in two important regards

- Diesel engine exhaust contains 10 to 12 percent O_2 compared to 2 to 4 percent for boilers
- The temperature of the exhaust leaving the diesel engine is about 900°F, much lower than the reburn gas temperature in boiler furnaces.

Fuel-lean reburning has been shown to be an effective NO_x control method in some combustion systems. Yang et al. (6) performed tests relative to process heater applications in which NO_x could be reduced by as much as 50 percent. Previously, various investigators (7-9) noted that NO_x formed in the gas turbine portion of a combined cycle power system could be destroyed under certain conditions in a duct burner or exhaust-fired heat recovery boiler flame. This non-optimized form of reburning may be very attractive for diesel systems whose very high NO_x emissions provide a large driving force for reburning.

Recently, Brown and Kirby (10) studied reburning for gas turbine and diesel applications. They concluded that when the exhaust O_2 content exceeded 11 percent, large amounts of reburning fuel (23 to 50 percent of the total heat input to the system) were required to achieve a 50-percent NO_x reduction. However, mixing rate was difficult to control in their 100,000 Btu/hr test facility.

Our application of this reburning concept is shown on Figure 5. The heart of the process is a low-NO_x reburner located in the gas stream. This reburner consists of a central fuel injector surrounded by a shroud to control the rate of fuel air mixing. The shroud is perforated to allow a portion of the exhaust to mix rapidly with the reburning fuel. Ideally this initial mixture would have an air/fuel stoichiometric ratio of 0.7 to 0.9 to allow stable ignition. The rest of the exhaust would pass around the shroud to mix slowly but completely as the excess reburning fuel (and NO) is consumed.

EXPERIMENTAL PROGRAM

As of early January, the PSIT experimental program was just beginning. Preliminary experiments will examine ammonia (and other reducing agents) injection upstream of a baghouse. The baghouse will utilize NOMEX filter material allowing operation up to a temperature of 450°F or ceramic fibers for higher temperature. The test program will involve systematic variations of the following parameters:

- Filter media: clean bag filter, filter plus lime, filter plus engine particulate, filter plus lime and engine particulate, filter plus activated carbon
- Temperature: 300°, 450°, 600°, 750°F
- Reducing agent: none, ammonia, other.

The key issues to be resolved during these tests are:

- Is engine particulate matter (80 percent carbon, 5 µm mean size, 22 m^2/g surface area) an effective NO_x reduction catalyst?

- Under what operating conditions is NO_x reduction maximized?

- Can the technology be integrated with a bag filter or will it require a separate reactor to maximize NO_x reduction?

Actual particles collected from the JS-1 engine will be characterized and tested by PSIT in these experiments.

Reburning experiments will also be conducted. Initial tests will involve systematic variation of the reburner components to define mixing conditions conducive to NO_x reduction. The bench-scale reburner has been fabricated as shown on Figure 6. This reburner is designed for easy modification to the fuel injector and the shroud to optimize NO_x reduction and burnout.

Once the optimum configuration is established, the following operating variables will be explored:

- Inlet NO_x concentration: 100 to 1300 ppm
- Inlet O_2 concentration: 8 to 19 percent
- Inlet gas temperature: 300° to 1800°F
- Reburn fuel flow: 10 to 40 percent of total heat input
- Exhaust gas inlet velocity: 4 to 20 ft/s
- Reburning fuel additives: to be determined.

The technical issues to be resolved during these tests include:

- What is the minimum NO_x emission achievable when applying reburning to coal-fueled diesel stationary power plants?

- Will the technology be limited by either low temperature or high/low O_2 concentration of the incoming exhaust gas?

- How much reburning fuel will be required to achieve at least a 50 percent NO_x reduction?

- What will be the temperature and composition of the gas leaving the reburner reactor, and will this impact the operation/design of downstream emission control or heat recovery components?

The results of the test, if successful, will result in the design of a reburner for testing an a 1.8 MWe engine at Cooper-Bessemer.

PRELIMINARY NO_x CONTROL SYSTEM DESIGN AND COSTS

The goal of this study is to quantify the cost and probability of success for the emission control system options. The analysis of the costs takes two forms. First, the cost of the equipment for the component technologies is presented. From these costs, comparisons are made among the various technologies for controlling the three major pollutants. Second, the capital and operating costs for integrated emission controls systems are presented as a function of system size.

Component Technologies

The cost of emission control equipment relative to the power output of the system (e.g., the cost per kilowatt of electricity generated) decreases as the size of system increases. In general, the relationship between cost and system capacity is not linear. Therefore, the cost calculations were performed for five systems that span the range of interest for small stationary engines. Table 3 details the size-dependent operating parameters for the five systems of interest. Each system consists of one or more engines (either 6 or 20 cylinder engine). Systems 1, 2, 3, and 5, labeled as cogeneration systems, include a waste heat boiler which makes 125 psig steam for process applications. System 4, a power generation system, does not have a waste heat boiler. In this configuration, no heat recovery from the exhaust gas takes place and a water quench unit is employed to reduce gas temperatures as required by pollution control equipment.

Schematic diagrams and materials lists for the NO_x control technologies under consideration are given on Figures 7 to 9. The materials list was used to estimate process capital costs according to the EPRI methodology. (11) The capital costs in $/kW presented herein represent Total Capital Investment divided by the net power production of each system.

The operating and maintenance cost is the sum of operating labor, maintenance (labor and materials), and overhead labor. The annual maintenance costs are estimated as a percentage of the process capital cost. The EPRI methodology suggests maintenance cost factors for different technologies. The maintenance cost is broken down as 40 percent labor and 60 percent materials. The overhead charge is computed as 30 percent of the operating and maintenance labor and is a charge for administrative and support labor.

Following the EPRI methodology, the operating and maintenance cost is broken down into a fixed component and a variable component. The fixed operating and maintenance cost is the product of the capacity factor (or the utilization) and the annual operating and maintenance costs; the balance of the cost is assumed to be variable. The variable operating cost has two components: consumables (power, chemicals, etc.) and operating and maintenance, as described above.

The total annual operating cost is the sum of the fixed operating and maintenance cost, the variable operating cost, and the cost of capital. The cost of capital is based on a 12-year depreciation period at 10 percent interest. The yearly charge for the cost of capital is 15 percent of the total capital investment. The operating cost is expressed in millions of dollars per year or in mills/kWh. The latter unit is the annual operating cost (expressed as thousandths of a dollar) divided by the total hours that the equipment runs (at 65 percent utilization this is equal to 5694 hr) and the power output of the facility (in kW).

Table 4 gives the cost of equipment for individual NO_x control technologies expressed on a per kilowatt basis in 1988 dollars. Note first that the commercial SCR process is by far the most expensive option, based on data available from A.D. Little Inc. for conventional diesel systems and EPRI data for an 80 MW_e coal-fired boiler (12). The cost of ammonia injection is high for the small engine but lower for larger engines because it is dominated by the costs of ammonia storage and handling, and process controls which are relatively insensitive to engine size.

The cost for reburning is the sum of the cost of a duct burner and NO_x monitoring equipment. One duct burner is used per engine. For the 6 cylinder engine, the burner must supply 4 MMBtu/hr of heat if the reburning process represents 20 percent of the total heat input. For the 20 cylinder engine, the burner must supply 13 MMBtu/hr. Three burner manufacturers were contacted; one quote was used for the duct burner costs because it was the most complete of the three.

Integrated Emission Control Systems

Currently, diesel-fueled stationary engines are not equipped with the kind of emission control technology that will be needed to meet NSPS with the coal-fueled engine. The emission control devices will have to be integrated with the engine system components. A schematic of the five integrated systems is illustrated in Figure 10. Only one engine is shown; in this study, we have made the preliminary decision that emission control equipment downstream of the turbocharger will be common to all engines in the system, i.e., exhaust gases from all engines are combined after the turbocharger. Approximate temperatures are indicated in the figure although the exact temperature will depend on the optimum temperature required for the individual emission control subsystems and on the engine exhaust conditions.

Figure 11 shows capital cost as a function of power plant size for the five emission control systems under consideration. Note that the two options pairing reburning or ammonia injection with sorbent injection for SO_2 control offer a wide cost advantage over commercial SCR. Options combining expensive NO_x control with inexpensive SO_2 control (and vice versa) fall in the middle. It should be noted that even if reburning and ammonia injection are both needed to meet NO_x emission regulations, the cost is likely to be less than an SCR system. Operating costs, shown on Figure 12, exhibit similar trends (a catalyst life of 2 years and a bag life of 1 year have been used to estimate these costs).

Since this study represents a preliminary design, with 20 to 30 percent uncertainty in the calculated costs, a formal sensitivity analysis has not been performed. However, two aspects of the sensitivity of the economic calculations to input data should be mentioned. First, the engine operating parameters and system configuration may change as a result of the on-going JS-1 test program. Second, the process parameters for control technologies may change as a result of the laboratory experiments and on more detailed discussions with manufacturers of commercially available technology. The target date for commercialization of the technology is 1995-2000.

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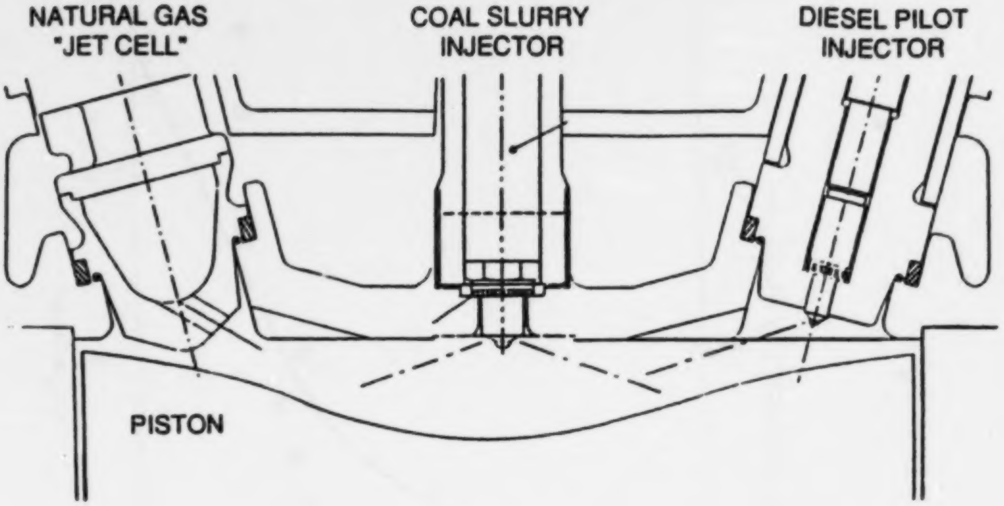

NATURAL GAS
"JET CELL"
COAL SLURRY
INJECTOR
DIESEL PILOT
INJECTOR
PISTON

Figure 1. Configuration of Test Engine

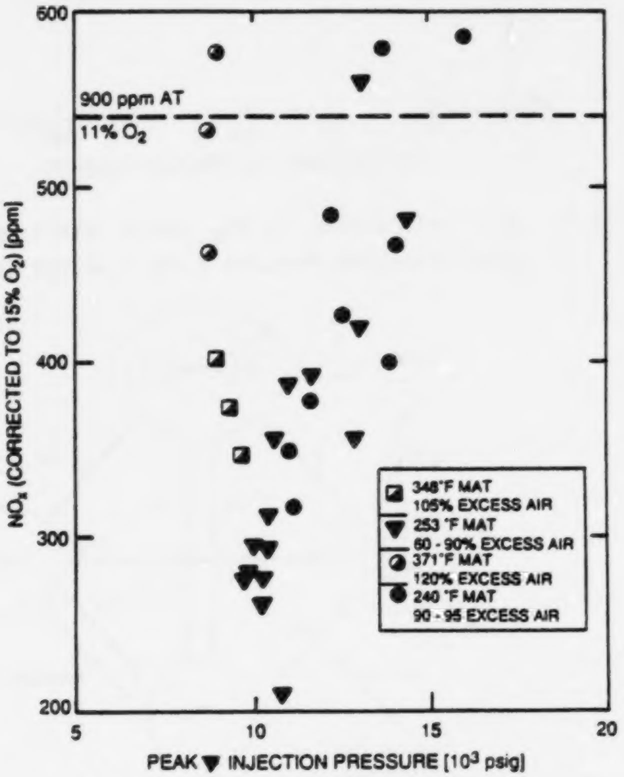


Figure 2. JS-1 Test Results for NO_x Versus Peak Injection Pressure

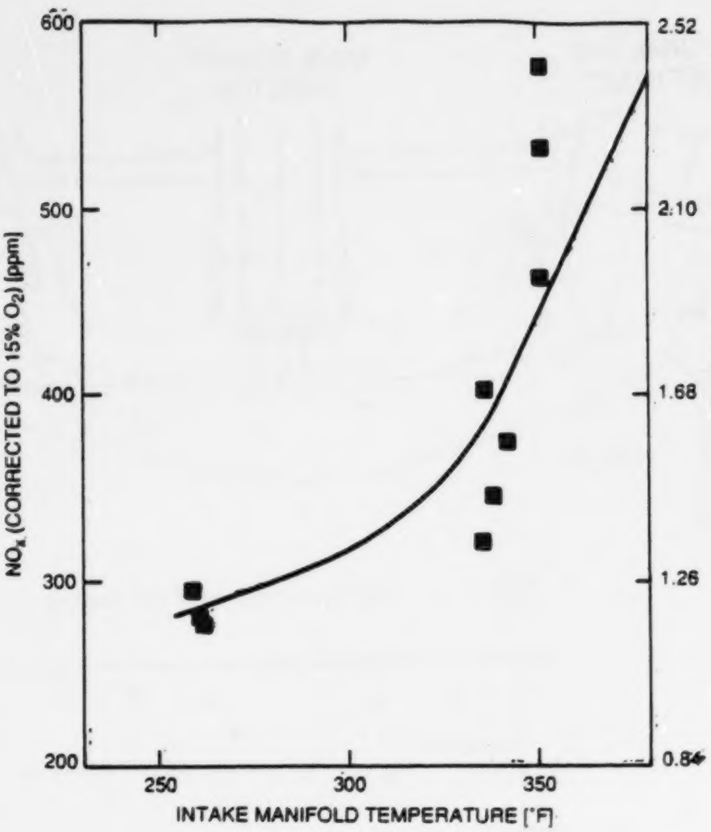
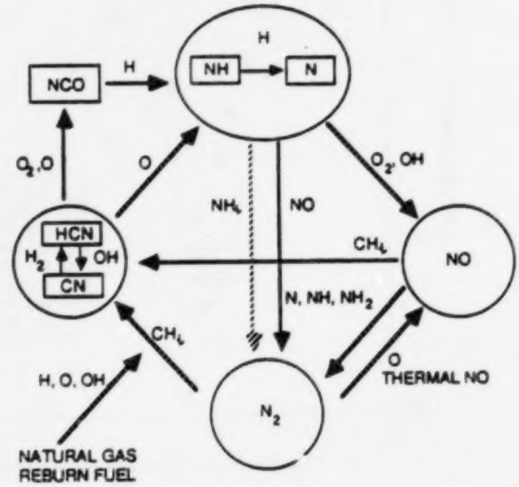


Figure 3. JS-1 Test Results for NO_x Versus Intake Manifold Temperature (Peak Injection Pressure 8,700 - 10,000 psig)



H
NH
N
NCO
H
O_2,O
O
O_2, OH
NH_i
NO
HCN
H_2
OH
CN
CH_i
NO
N, NH, NH_2
CH_i
H, O, OH
O
THERMAL NO
N_2
NATURAL GAS
REBURN FUEL

Figure 4. NO_x Formation and Destruction Pathways During Natural Gas Reburning

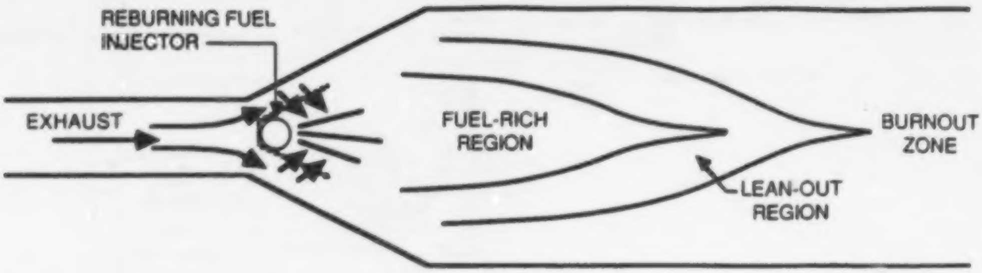

REBURNING FUEL INJECTOR
EXHAUST
FUEL-RICH REGION
LEAN-OUT REGION
BURNOUT ZONE

Figure 5. Reburn Schematic - Plan View

Photo to come

Figure 6. Laboratory-Scale Reburner

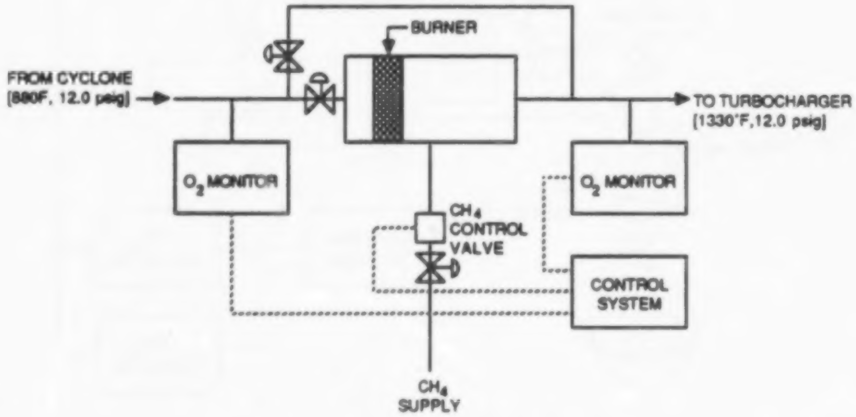

BURNER
FROM CYCLONE [880F, 12.0 psig]
TO TURBOCHARGER [1330°F,12.0 psig]
O2 MONITOR
O2 MONITOR
CH4 CONTROL VALVE
CONTROL SYSTEM
CH4 SUPPLY

Figure 7. Reburning

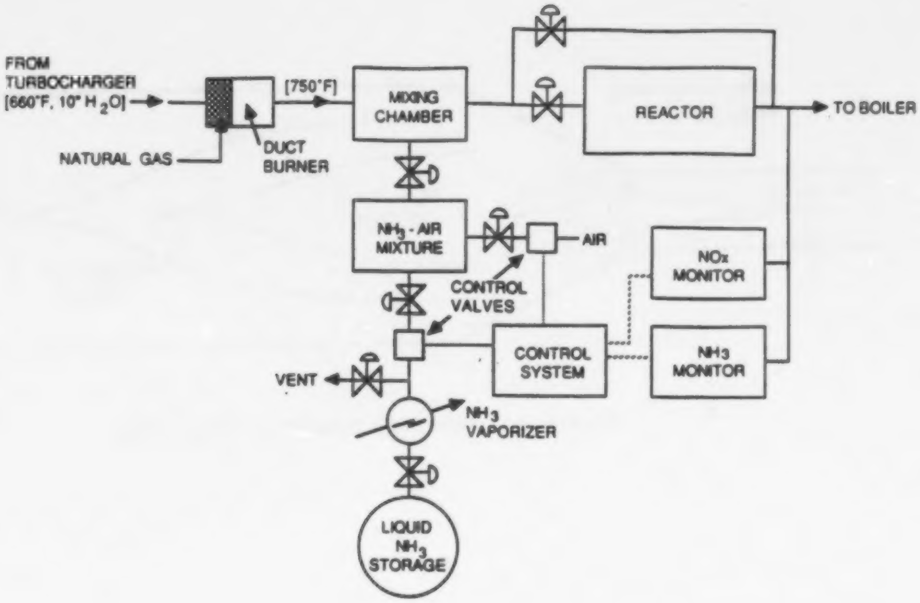

FROM TURBOCHARGER [660°F, 10" H2O]
NATURAL GAS
DUCT BURNER
[750°F]
MIXING CHAMBER
REACTOR
TO BOILER
NH3 - AIR MIXTURE
AIR
CONTROL VALVES
NOx MONITOR
CONTROL SYSTEM
NH3 MONITOR
VENT
NH3 VAPORIZER
LIQUID NH3 STORAGE

Figure 8. Selective Catalytic Reduction

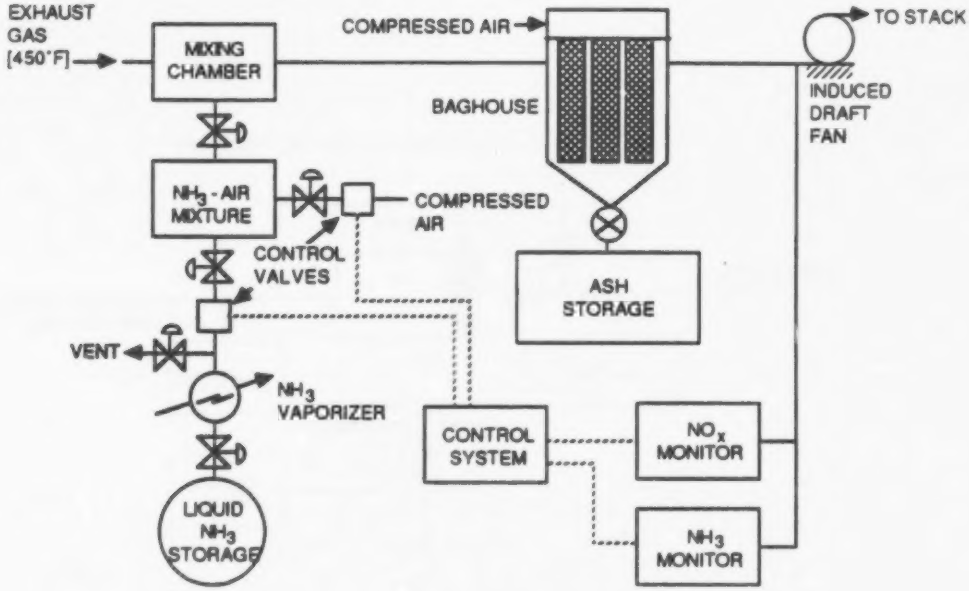
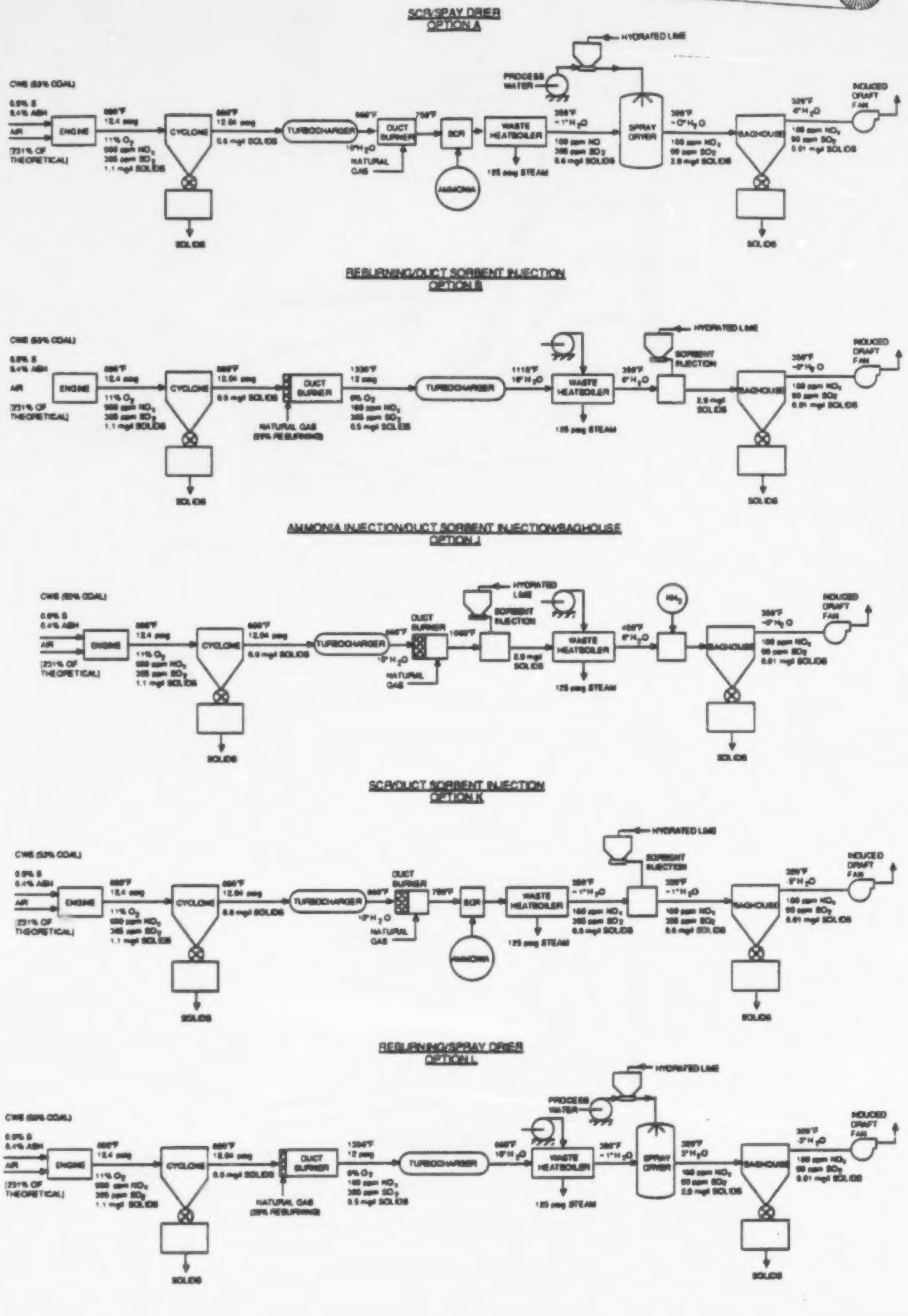

EXHAUST GAS [450°F]
MIXING CHAMBER
COMPRESSED AIR
BAGHOUSE
TO STACK
INDUCED DRAFT FAN
NH3 - AIR MIXTURE
COMPRESSED AIR
CONTROL VALVES
ASH STORAGE
VENT
NH3 VAPORIZER
CONTROL SYSTEM
NOx MONITOR
NH3 MONITOR
LIQUID NH3 STORAGE

Figure 9. NH_3 Injection in Baghouse

Reproduced from best available copy.



SCR/SPAY DRIER OPTION A

REBURNING/DUCT SORBENT INJECTION OPTION B

AMMONIA INJECTION/DUCT SORBENT INJECTION/BAGHOUSE OPTION J

SCR/DUCT SORBENT INJECTION OPTION K

REBURNING/SPRAY DRIER OPTION L

CWS (53% COAL)
0.9% S
0.4% ASH
AIR
(231% OF THEORETICAL)
ENGINE
12.4 psig
11% O_2
CYCLONE
12.04 psig
TURBOCHARGER
DUCT BURNER
NATURAL GAS
NATURAL GAS (20% REBURNING)
SCR
AMMONIA
NH_3
WASTE HEATBOILER
125 psig STEAM
PROCESS WATER
HYDRATED LIME
SORBENT INJECTION
SPRAY DRYER
BAGHOUSE
100 ppm NO_x
0.01 mg/l SOLIDS
INDUCED DRAFT FAN
SOLIDS

Figure 10. Integrated Emission Control Systems Under Consideration

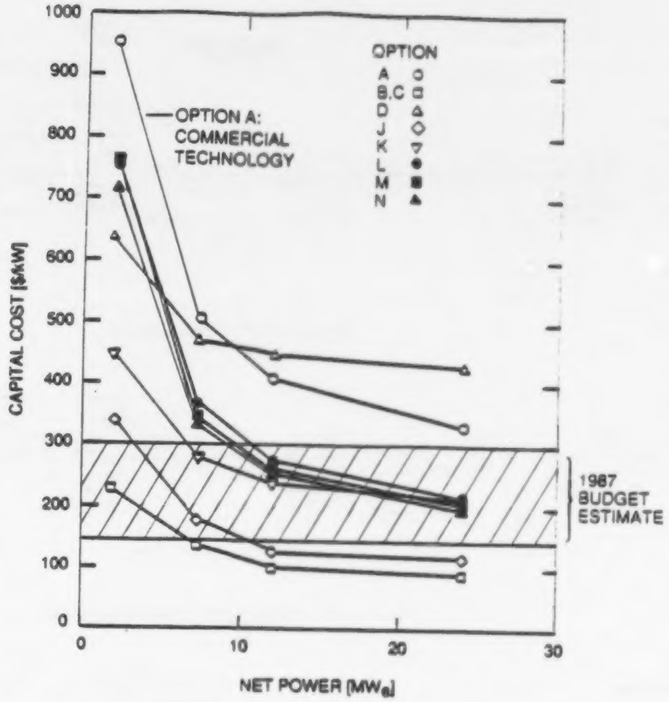


Figure 11. Capital Cost for Cogeneration System

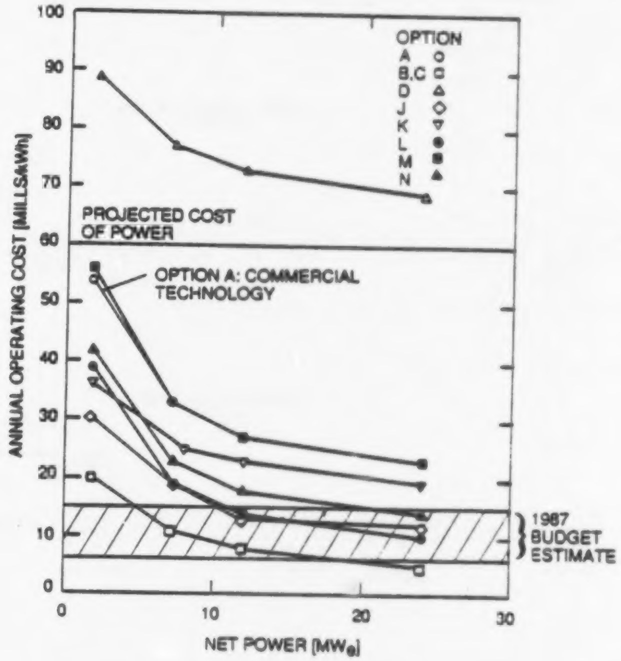


Figure 12. Annual Operating Cost for Cogeneration Systems

Table 1

COMPARISON OF NO_x EMISSION FROM JS-1 ENGINE
FOR EACH FUEL TYPE

Manifold Air Temperature (°F)	NO_x Emission DF-2 Only		NO_x Emission CWF + DF-2		NO_x Emission CWF Only	
	ppm @ 15% O_2	lb/MBtu	ppm @ 15% O_2	lb/MBtu	ppm @ 15% O_2	lb/MBtu
340	403	1.69	426	1.79	-	-
440	657	2.52	725	3.04	-	-
434	-	-	1029	4.32	907	3.81
426	864	3.63	696	2.91		

Table 2

EMISSION CONTROL SUBSYSTEMS

NO_x Control

- Reburning
- SCR: Commercially available unit
- SCR: Ammonia injection over engine particulate catalyst at 450°F in baghouse
- SCR: Ammonia injection over CuO catalyst at 750°F in granular bed reactor (Shell/UOP) process
- Adsorption on engine particulate bed at 275°F in baghouse

Table 3

PROCESS PARAMETERS FOR COAL-FUELED DIESEL SYSTEMS

Engine →	1 LSB 6	2 LSB 6	3 LSVB 20	4 LSVB 20	5 LSVB 20
Application	Co-gen	Co-gen	Co-gen	Power	Co-gen
Number of Engines	1	4	2	2	4
Net power output (MW_e)	1.8	7.2	12	12	24
Total horsepower	2,516	10,064	16,772	16,772	33,544
Coal flow (lb/hr)	1,154	4,616	7,692	7,692	15,384
Heat input (MMBtu/hr)	15.86	63.44	105.66	105.66	211.32
Exhaust gas flow (scfm) single engine	6,979	6,979	23,260	23,260	23,260
Total (all engines)	6,979	27,916	46,520	46,520	93,040
Exhaust gas flow (klb/hr) single engine	30.9	30.9	103.0	103.0	10.30
Total (all engines)	30.9	123.7	206.1	206.1	412.2
Emissions (lb/hr)					
SO_2	21	84	140	140	280
NO_x	45	178	297	297	594
Solids	27	110	183	183	365

Table 4

EQUIPMENT COSTS FOR NO_x CONTROL TECHNOLOGIES

	Cost ($/kW) as a Function of System Size:				
Subsystem Option	Installation Multiplier[1]	1.8 MW	7.2 MW	12 MW	24 MW
Reburning	0.33	18	18	9	9
NH_3 Injection in baghouse at 450°F	0.40	47	12	8	5
Commercial SCR	0.37	92	60	53	43

[1] To calculate installation cost, multiply equipment cost by the installation cost multiplier

Session 5B

INCINERATION

Chairman: W. Linak, EPA

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Reduction of NO_x Emissions From MSW Combustion Using Gas Reburning

by

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ABSTRACT

A program has been initiated to evaluate the potential for reducing air pollutant emissions from Municipal Solid Waste (MSW) combustion systems using natural gas reburning. The program is being conducted jointly by the Institute of Gas Technology, the Gas Research Institute, Riley Stoker Corporation and Takuma Company Ltd.

Three major tasks are included in the program: (1) acquisition of baseline data from a commercial operating facility, (2) pilot-scale development and testing of the reburning technology, and (3) field demonstration testing of the technology. This paper focuses on the results to date of the first two tasks: baseline data acquisition and pilot scale testing.

The gas reburning concept being evaluated for MSW combustion is similar to the reburning technique being investigated to reduce NO_x emissions from fossil fuel combustion systems. Natural gas is introduced above the main combustion zone to create a reducing environment where significant amounts of NO_x and other fixed nitrogen species (NHi, HCN), generated in the main combustion zone, are reduced to molecular N_2.

Results of the pilot scale testing have demonstrated up to 70% reduction in NO_x emissions using gas reburning. The effects of gas injection location, reburning zone stoichiometry and residence time, overall boiler excess air and the amount of natural gas reburning on NO_x emissions are characterized. The impact of gas reburning on reducing other emissions such as CO, unburned THC and dioxin is also discussed.

INTRODUCTION

With the expanding waste-to-energy market today, the need to understand more about the combustion characteristics and behavior of municipal solid waste (MSW) and refuse derived fuel (RDF) has increased dramatically. Of primary concern are the air pollutant emissions produced during the combustion process and the ability to control these emissions. Flue gas scrubbers are generally employed in modern facilities at the boiler exit to control the acid gas emissions such as HCl and SO_2. Baghouses or electrostatic precipitators are used to remove the particulate emissions as well as the reacted lime from the scrubber. Other emissions could potentially be controlled during the combustion process. These include NO_x, CO, unburned THC, polychlorinated dibenzodioxins (PCDD's) and polychlorinated dibenzofurans (PCDF's).

In April, 1987, the Institute of Gas Technology (IGT), the Gas Research Institute (GRI), Riley Stoker Corporation (Riley) and Takuma Company Ltd. from Japan (Takuma) began work on a research program to evaluate the potential for reducing pollutant emissions from MSW combustion systems using natural gas. The primary objective of the overall program is to investigate the use of natural gas reburning in combination with low excess air operation to minimize the production of NO_x emissions. As conceptually shown in Figure 1, natural gas would be introduced above the main combustion zone in a MSW combustor to create a strong fuel rich or reducing zone where NO_x and other fixed nitrogen species (NH_i, HCN), generated in the main combustion zone, would be reduced to harmless molecular nitrogen. Natural gas reburning might also serve to reduce other pollutant emissions such as CO, unburned HC, PCDD's and PCDF's by creating a more uniform and stable thermal environment in the combustor.

Other benefits expected from this type of boiler operation are improved combustion efficiency, increased boiler efficiency and more stable, reliable operation of the system. As outlined below, the research program is divided into three major tasks. Task 1 was completed in the fall of 1987 while Task 2 is nearly complete.

Task 1 - Acquisition of Baseline Data From a Field Operating Unit.

Task 2 - Pilot Scale Development and Testing of the
Gas Reburning Technology.

Task 3 - Field Demonstration Testing at a Commercial Installation

This paper discusses the results to date of Tasks 1 and 2. Due to the initial favorable results incurred during the pilot scale testing at both IGT and Riley, preliminary plans are currently being formulated for a field demonstration test of the gas reburning technology.

GAS REBURNING TECHNOLOGY

The gas reburning technology being developed in this program is similar to the reburning techniques being investigated to reduce NO_x emissions from coal fired combustion systems. As shown in Figure 1, gas would be injected into the furnace through multiple openings above the main combustion zone at 10-15% of the total heat input. Recirculated flue gas, equal to 10-20% of the total boiler flue gas approaching the take off point, would be used to convey the natural gas and achieve the proper penetration and mixing required in the furnace. Overfire air (OFA), would then be added above the gas reburning zone to complete the combustion process.

The reburning zone created by the natural gas would provide the H and OH radicals necessary to react with and reduce the NO_x and other fixed nitrogen species, generated in the main combustion zone to molecular N_2. As discussed later in this paper, the NO_x emissions being produced from a typical Riley-Takuma mass burn system (1) average 150 PPM(1). Our goal is to reduce the NO_x emissions to 50 PPM, comparable to the levels currently attainable only by selective catalytic reduction (SCR) or urea injection (2, 3).

Another benefit anticipated from using gas reburning is the ability to create a more uniform and stable thermal environment within the furnace, thus eliminating localized low temperature zones and pathways. As described later, furnace temperature fluctuations on the order of ±150°F, over a one minute period, were measured during the baseline testing at a commercial facility while burning only MSW. Temperature differences as large as 160°F between the front and rear walls were also measured. These erratic temperature profiles may contribute to products of incomplete combustion (PIC) emissions by allowing the reactions to occur at insufficient temperature. Work by Duvall shows that below approximately 1500°F, thermal destruction of many PIC's begins to rapidly decrease (4). Gas reburning should, therefore, enhance the burnout of CO, unburned THC, PCDD's and PCDF's by creating a more uniform temperature environment in the furnace.

Gas reburning, in combination with low excess air operation, should also improve boiler efficiency. Reducing the overall excess air requirement from the current 80% to 40% could potentially increase boiler efficiency by 1.5%.

BASELINE FIELD TEST RESULTS

In July 1987, parametric field tests were performed during Task 1 by Riley and IGT on Unit 1 of the Olmsted County Waste-to-Energy facility in Rochester, Minnesota. This 100 ton/day unit, shown in Figure 2, was designed and constructed by Riley to incorporate the Japanese technology for mass burning that Riley licenses from C. Itoh Takuma Ltd., Japan. As shown in Figure 3, the Takuma stoker consists of four separate sections: feeder table, drying and ignition grate, combustion grate and burnout grate.

Between the grate sections are two to three foot drops or steps which reduce top to bottom fuel stratification and help to break up any large agglomerations of the fuel. By hydraulically reciprocating every other individual grate row, the fuel cascades and moves down the various grate sections. Fuel drying, pyrolysis and ignition occur on the drying and ignition grate. About 95% of the fuel combustion occurs on and over the combustion grate. The burnout grate provides time for carbon burnout and reduction of putriscibles under locally high excess air conditions. The Riley-Takuma systems are designed to handle refuse throughputs from 100-1000 tons per day.

During the field tests at Olmsted County, pollutant emissions were measured at the economizer exit or precipitator inlet as well as at critical locations in the furnace. These emissions included NO_x, SO_2, CO, unburned THC and putriscibles in the ash. Tests were conducted while varying the amount and location of OFA, undergrate air (UGA), excess air and boiler load. Using suction pyrometers, furnace gas temperature measurements were also collected in the upper furnace and furnace backpass. However, attempts to measure furnace gas temperature in the lower furnace immediately above the grates were unsuccessful due to probe plugging.

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(1) All emissions have been corrected to 12% O_2 unless stated otherwise.

Results of the testing showed that operation of the overfire air (OFA) system had the most significant effect on controlling NO_x, CO and unburned THC emissions. The amount of OFA had the greatest impact. Since excess air is automatically controlled by the amount of OFA (1), increasing excess air would cause an increase in the NO_x and a decrease in CO emissions, typical of most combustion systems. This is shown in Figure 4. At design excess air operation, NO_x emissions entering the electrostatic precipitator averaged 150 PPM while CO was 28 PPM. Unburned THC emissions measured at this same location averaged less than 5 PPM. In general, the CO emissions would only increase at very low levels of excess air (<30%) when OFA was completely closed. But, the level would still remain below 200 PPM.

Detailed in-furnace gas composition measurements showed the effect of OFA in controlling emissions. Figure 5 summarizes the gas composition history measured at various locations throughout the entire unit during full load normal operation. NO_x increases following the addition of OFA while CO and unburned THC are reduced significantly. Less than 50% of the total NO_x emission is formed immediately above the grate while the remaining NO_x is formed in the OFA region. In addition, since the predicted peak furnace temperature in this area remains below 2400°F, NO_x is primarily formed from the conversion of fuel bound nitrogen.

Figure 6 shows the gas temperature history of the unit based on actual furnace temperature measurements and calculated flue gas flows. Furnace temperatures are typically less than 2400°F. However, not shown on the figure, are the significant temperature fluctuations and stratification measured in the furnace. During several tests, fluctuations of ±150°F over a one minute period were measured while the temperature difference between front and rear furnace walls was as large as 160°F. Though the CO and unburned THC emissions remain relatively low with this type of thermal environment, the benefit of using natural gas reburning to stabilize this environment may potentially reduce these emissions even further as well as provide the environment for reductions in PCDD's and PCDF's.

The results of the testing at Olmsted County were then used to form the basis for the pilot scale testing performed initially at IGT in a furnace simulator and then at Riley in an actual pilot MSW combustion facility. The purpose of the testing at IGT was to initially investigate the feasibility of using gas reburning to reduce NO_x emissions and to identify those variables which had the most significant impact on controlling NO_x. The test variables included:

- reburning zone residence time
- reburning zone stoichiometry
- reburning zone temperature
- amount of natural gas reburning fuel
- amount of flue gas recirculation (FGR) for natural gas transport
- overall stoichiometry leaving the furnace

Subsequent testing at Riley Stoker was then performed to further characterize and define an optimum gas reburning strategy that would be directly transferrable to a commercial installation. The following section briefly describes the major results of the pilot scale testing at IGT followed by a more detailed discussion of the initial process development tests conducted at Riley Stoker.

IGT PILOT SCALE TESTING (TASK 2)

One of the pilot-scale furnaces, at IGT's Applied Combustion Research Facilities, was modified to simulate the combustion products measured in the lower furnace section of the Olmsted County MSW combustor. As shown in Figure 7, combustion products, that would result from firing MSW at a rate of 1.7 x 10^6 Btu/hr, were simulated by firing No. 2 fuel oil into preheated combustion air with subsequent blending of water, ammonia and oxygen. The hot combustion products were introduced into one end of the 4.5 ft wide x 3 ft high x 14 ft long furnace chamber and distributed across the furnace cross section using a refractory grid. The furnace chamber was refractory lined and equipped with cooling tubes to simulate the thermal environment measured in the field.

In the combustion chamber, the natural gas for reburning, conveyed by recirculated flue gas, was introduced through holes in the top and bottom of a 4" diameter stainless steel pipe. This injector, extending the full width of the combustor, was placed at the centerline of the combustion chamber just downstream of the distribution grid. Secondary air, simulating overfire air, was also introduced through a similar injector design, downstream of the reburning zone, to complete the burnout. The furnace is equipped with 32 removable doors along the length which allowed for significant flexibility in the placement of these injectors and probes.

The reburn zone stoichiometry and temperature were changed by varying the amount and temperature of the preheated combustion air, while reburn zone residence time was varied by placing the secondary air injector at various locations along the furnace length. Test measurements focused on gas composition (O_2, CO, THC, CO_2 and NO_x) and temperature in both the reburn zone and at the furnace exit.

Table I shows a comparison of the gas composition measured without gas reburning in the IGT furnace simulator with the gas composition measured in the baseline test furnace at Olmsted County. The pilot-scale results showed good agreement in regards to gas composition, furnace temperature and residence time. NO_x emissions varied (100 - 300 PPM) primarily depending on the amount of NH_3 injected into the flue gas products.

Testing the affect of gas reburning on reducing NO_x emissions showed very promising results. NO_x reductions of up to 70% were measured. The most significant variable was the stoichiometric ratio of the reburning zone. As shown in Figure 8, NO_x decreased with decreasing stoichiometry. NO_x emissions were reduced significantly down to a reburn zone stoichiometry of approximately 0.6-0.9, depending on residence time. A stoichiometric ratio of 0.9 utilized 15% natural gas for reburning in combustion products that originally had a stoichiometric ratio of 1.1.

Figure 8 also shows the effect of the reburn zone residence time on NO_x reduction. The results show that longer residence times are more beneficial in reducing NO_x. The difference between 1.0-1.4 seconds and 4.0-5.2 seconds was 40-50 PPM more NO_x reduction for the longer times. The shorter residence times are, however, more practical for commercial applications. Residence times on the order of 2.0-2.5 seconds in the reburn zone of a Riley-Takuma system are possible. As shown in Figure 9, at 2.5 seconds residence time, NO_x reductions of 50% were measured.

The furnace temperature in the reburn zone was not a critical factor in reducing NO_x emissions within the temperature range tested, 1950°F-2400°F. Any temperature effects were dominated by other more significant parameters. In regards to other emissions, though, CO was reduced from 30-40PPM without gas reburning to <20PPM with 15% gas reburning.

The major findings drawn from this initial testing of the gas reburning concept, on IGT's Pilot-Scale Furnace Simulator, are summarized below:

- Up to 70% NO_x reduction was achieved with 15% gas reburning and 4.0-5.2 seconds residence time in the reburning zone.
- Residence times of approximately 2-2.5 seconds in the reburning zone appears to be sufficient for 50-60% NO_x reduction.
- Reburn zone temperatures are less critical than residence time and stoichiometry for NO_x reduction.
- Reburn zone stoichiometry of 0.9 is effective in controlling NO_x and is attainable in commercial installations.
- There is potential for reducing CO emissions using gas reburning.

RILEY STOKER PILOT SCALE TESTING (TASK 2)

Following the initial pilot scale testing at IGT, process development tests were conducted at Riley in a $3x10^6$ Btu/hr Pilot MSW Combustion Facility. The pilot scale step grate stoker design is an actual prototype of a full scale Riley-Takuma system for mass burning. As conceptually shown in Figure 10, the combustor section is 17'-0" tall x 11'-9" long x 3'-0" wide and is designed to burn processed MSW at a rate of approximately 450 lb/hr or 5.5 tons/day.

Processed MSW, from an RDF plant in Biddeford, Maine, rather than raw MSW is burned. The majority of the glass and metals content has already been removed and the refuse has been reduced in size. This was done to avoid mechanical operating problems which would result from raw MSW. Table II shows a comparison of the processed MSW with the MSW from Olmsted County.

The pilot facility includes a 10 ton storage trailer, 45 ft long drag chain conveyor, refuse feed chute, stoker grate and hydraulic drive system, ash discharge hopper, overfire air nozzles, natural gas injection nozzles, undergrate air, a flue gas recirculation system and a startup gas burner. The furnace walls of the combustor are water cooled with high insulating refractory attached to the inside surface to produce a thermal environment typical of field operating conditions.

Figure 11 shows a photograph of the main combustor section. Combustion products exit the main combustor and pass through heat recovery equipment, a gas analysis sampling train, baghouse, acid gas scrubber system and finally exhaust out the stack. The gas analysis train at the furnace exit is used to continuously monitor flue gas composition including NO_x, O_2, CO, THC, CO_2 and SO_2. The facility is currently being equipped to monitor HCl. In-furnace gas composition and temperatures are measured as desired through various sampling ports located throughout the combustor. A data acquisition and computer system is used for direct on-line data analysis of various test conditions.

Similar to the testing performed at Olmsted County, baseline testing was first conducted in the Pilot MSW Combustion Facility to ensure the results were comparable to the field data. Normal operating conditions were simulated in regards to excess air, % OFA flow, OFA and UGA flow distribution and the burning profile of the processed MSW on the grates.

Figure 12 shows the computer output for a typical baseline performance test during normal or standard operating conditions. Pertinent information regarding load, flue gas composition, furnace zone stoichiometric ratios (SR), temperatures (T) and residence times (t) are identified as well as the actual fuel and air flows. NO_x, CO and THC emissions for this one test measured 142, 27 and 0 PPM, respectively. For all the baseline testing under normal operating conditions the NO_x, CO and THC emissions varied as follows:

NO_x	120 - 165 PPM
CO	10 - 50 PPM
THC	0 - 2 PPM

The furnace exit temperature indicated in Zone 5 (1570°F) was actually measured with a high velocity temperature (HVT) probe while all the other furnace temperatures were calculated based on the amount of heat removed in each furnace section.

Comparing these results with the field data collected at Olmsted in Table III showed good agreement in regard to flue gas emissions and furnace temperatures. The only discrepancy discovered was with furnace residence time. The residence times at Olmsted were calculated to be approximately twice as long as the pilot unit because of the physical scale differences. However, based on the pilot testing performed at IGT, longer residence times are more beneficial for NO_x reduction. So, the test results obtained in the Riley pilot unit, when testing the effects of gas reburning, should be conservative.

Additional baseline testing was performed in the Riley Pilot unit to evaluate the impact of varying OFA injection location on NO_x emissions. The normal or standard configuration is to introduce approximately 35% of the total combustion air through the lower front (LF), middle front (MF) and lower rear (LR) OFA nozzles. Refer to Figure 12 for the location of these nozzles. NO_x emissions during normal operation with 70% excess air averaged 120-165 PPM. However, introducing the same amount of OFA through only one location (LF or LR) caused an increase in NO_x to 200-220 PPM. CO emissions remained unchanged. The higher NO_x is attributed to greater turbulence and mixing in the lower furnace and a subsequent increase in fuel NO_x conversion.

Conversely, the lowest NO_x can be produced by completely closing the OFA and maintaining 50-60% total excess air. Tests showed that NO_x could be reduced to 109 PPM but CO emissions increased significantly to 150 PPM and THC emissions were measured to be 6 PPM. Again, similar to the field operating unit, operation of the OFA system in the pilot unit had a significant effect on controlling NO_x, CO and unburned THC emissions. Variations in excess air, unit load and undergrate air distribution had no appreciable effect on combustion performance and emissions.

Tests were then performed to evaluate the impact of gas reburning on reducing emissions. The primary variables focused on natural gas and FGR quantity, natural gas, FGR and OFA injection location and furnace stoichiometries. As summarized in Table IV, the initial results were very encouraging. This data was collected at 2.0-2.5 x 10^6 Btu/hr unit load with approximately 32-34% OFA. From a baseline NO_x level of 120-165 PPM, NO_x could be reduced to approximately 70-80 PPM or nearly 50%. Figure 13 shows the effect of reburn zone stoichiometric ratio on NO_x emissions both with and without gas reburning. Typically, this ratio averaged 1.4 without and 0.9 with gas reburning. The scatter in the data is due to variations in load, overall excess air, grate stoichiometry and gas injection location.

Gas reburning was indeed effective in controlling NO_x. The low levels of CO and THC emissions measured during the baseline testing would also remain low using gas reburning. CO emissions were measured at <25 PPM while THC emissions would remain at only a trace.

However, these favorable results were very dependent on the injection method and type of operation being used. The best approach for maximum emission reduction evaluated during this initial testing was to operate the reburning system as outlined below, which corresponds to Test 53.

- 17% FGR through LF and LR nozzles
- 13% natural gas through LR nozzles only
- 34% OFA through upper front (UF) and upper rear (UR) nozzles
- 31% overall excess air

All other system operating conditions remained the same as during the baseline testing. The resulting reburn zone stoichiometry for Test 53 was 0.87 while reburn zone residence time was calculated to be .91 seconds.

Introducing natural gas through the lower rear nozzles, immediately above the combustion grate, was also very effective during earlier tests (41-43) in reducing NO_x but CO emissions exceeded 80 PPM. The reason for this is because FGR was only being introduced through these same nozzles, and the high degree of turbulent mixing, resulting from introducing FGR through both the LF and LR nozzles, was not as pronounced.

Test 52 demonstrated that low levels of NO_x could still be produced when using only 7% natural gas for reburning. However, as shown in Figure 14, this occurred only when natural gas was introduced through the LR nozzles. Introducing gas through the LF nozzles for reburning would create a situation where the degree of NO_x reduction was much more dependent on the amount of natural gas being burned.

Tests 47 and 48 evaluated the effect of introducing OFA through the middle front (MF) and middle rear (MR) nozzles. This would produce shorter residence times for NO_x reduction reactions to occur in the reburning zone. Residence times for these tests were calculated to be only 0.65 seconds as compared to >0.90 seconds when introducing OFA through the UF and UR nozzles. During these tests, NO_x emissions were only reduced 28-38% depending on the amount of gas reburning being used. This showed the importance of reburn zone residence time on NO_x reduction. Figure 15 graphically shows the effect of reburn zone residence time on NO_x emissions from this testing. As discussed later, additional testing, to study the effect of increasing this residence time to levels approaching 1.5 seconds, will be performed, since residence times of 2.0-2.5 seconds can be obtained in commercial installations.

Further analysis of the data to evaluate the effects of grate stoichiometry and overall excess air is currently being performed. Preliminary indications are that these variables do not have as significant an impact on emissions reduction as reburn zone stoichiometry, residence time and gas injection strategy. The data does show that low NO_x levels can be achieved without having to operate the grates at sub-stoichiometric combustion air levels.

The major findings based on initial testing of the gas reburning concept are as follows:

- 50% NO_x reduction was achieved with 7-15% natural gas reburning. Introducing the gas through the lower rear nozzles was the most effective.

- Effective burnout of CO and THC emissions can be achieved using gas reburning.

- The ability to control emissions using gas reburning is very dependent on injection location, residence time and reburn stoichiometry.

- A reburn zone stoichiometry of approximately 0.9 is effective in reducing NO_x while residence times >.85 seconds are required for sufficient reactions to occur, i.e. >40% NO_x reduction.

- It appears excess air levels can be reduced from the normal 70% to 30% using gas reburning without adverse effects on emissions.

- No significant increase in furnace exit gas temperature was measured with gas reburning operating.

- Operating with 7-15% natural gas improved furnace heat input stability resulting in less variation in the measured O_2 concentration at the furnace exit. The variation decreased from ±2% without to ±1% with gas reburning.

FUTURE WORK

Testing in Riley Stoker's Pilot MSW Combustion Facility will continue to further optimize the gas reburning system. Test variables will focus primarily on increasing reburn zone residence time and modifying lower furnace mixing in an effort to obtain > 50% NO_x reduction while maintaining low CO and THC emissions. Modifications will be made to introduce OFA as high in the furnace as possible in order to maximize residence time. This will provide the capability of testing residence times > 1.5 seconds. The best injection strategy determined during the initial testing will continue to be studied along with variations of this approach such as reducing the amount of FGR and changing FGR injection locations.

Following determination of the final gas reburning configuration, more detailed in-furnace testing will be performed to better characterize the gas composition and temperature history throughout the furnace both with and without gas reburning. Dioxin measurements will also be collected.

Assuming success with the final pilot scale testing, plans for a field demonstration test of this technology in a commercial operating facility will be finalized during Task 3. A detailed economic analysis of the gas reburning technology will be conducted to determine the economic advantage of utilizing natural gas for emissions control. Boiler performance analysis will also be performed to quantify the impact of a gas reburning system on overall boiler performance. If these final analyses are encouraging, a field demonstration program of the gas reburning technology will be implemented.

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1) Itse, D.C. and Penterson, C.A., "Riley-Takuma Technology for Refuse Combustion Plants," presented at the AFRC International Symposium on Incineration of Hazardous, Municipal, and Other Wastes, Palm Springs, California, November, 1987.

2) Yamagishi, M., Yokohama, T., Shibuya, E. and Nippon Kokan K.K., "Air Pollution Control for Waste-to-Energy Plants," presented at the AFRC International Symposium on Incineration of Hazardous, Municipal, and Other Wastes, Palm Springs, California, November, 1987.

3) Fleming, D.K., Khinkis, M.J., Abbasi, H.A., Linz, D.G. and Penterson C.A., "Emissions Reduction from MSW Combustion Systems Using Natural Gas," presented at the Energy from Biomass Conference, New Orleans, Louisiana, February, 1988.

4) Duvall, D.S. and Ruby, W.A., "Laboratory Evaluation of High-Temperature Destruction of Polychlorinated Biphenyls and Related Compounds", EPA/600/14.

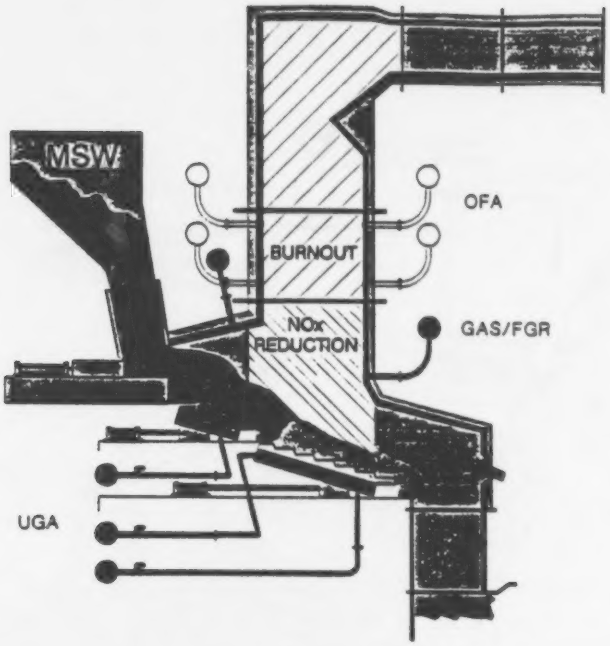

MSW
OFA
BURNOUT
NOx REDUCTION
GAS/FGR
UGA

Figure 1. MSW Gas Reburning Concept

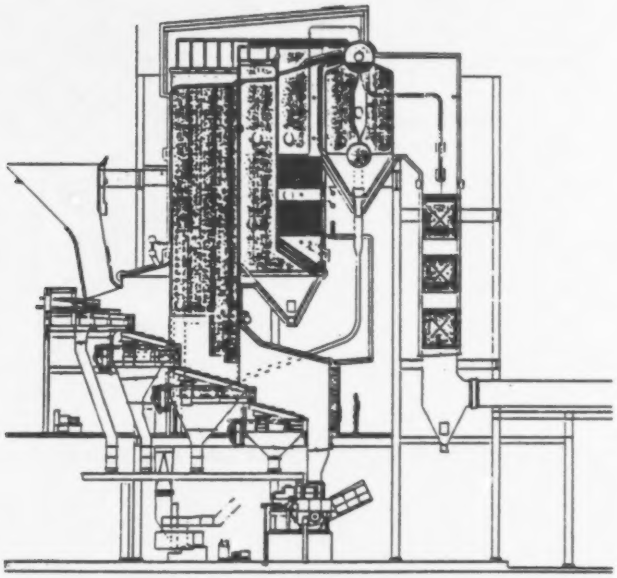


Figure 2. Riley-Takuma Waste to Energy Facility, Olmsted County, Minnesota

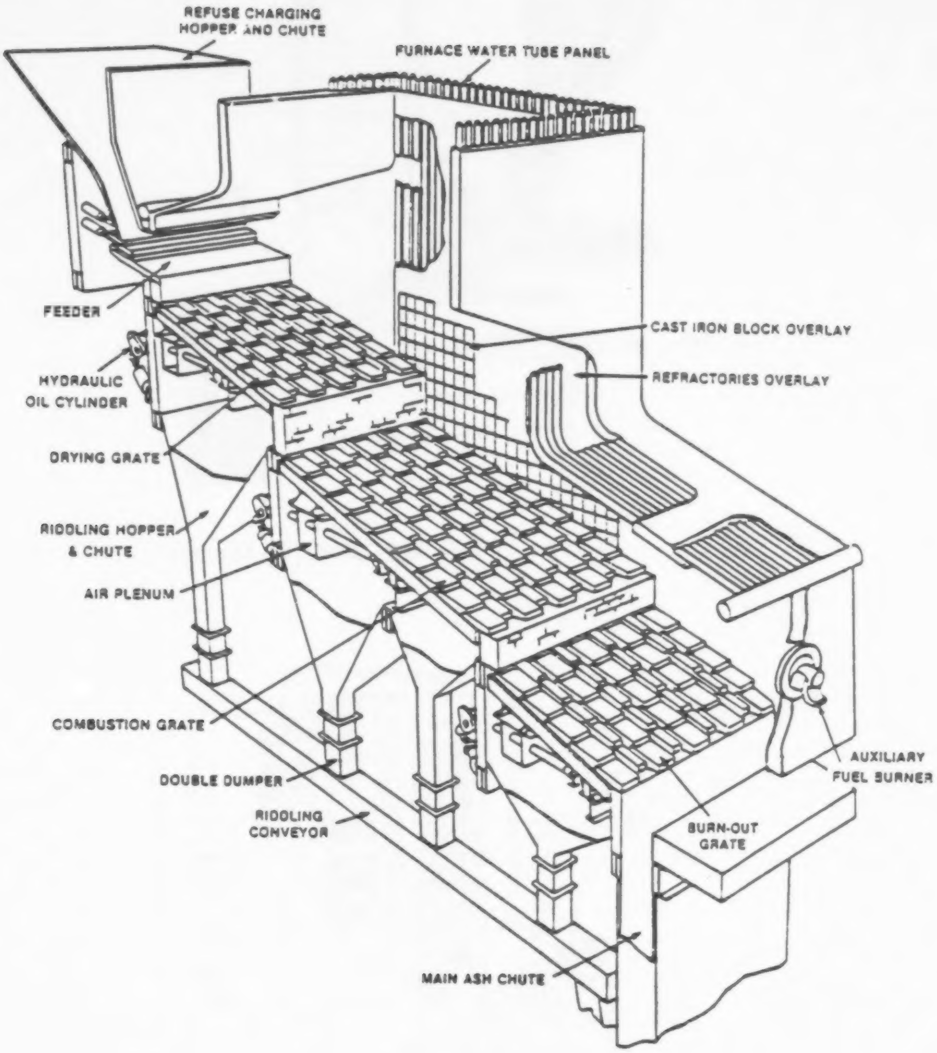

REFUSE CHARGING HOPPER AND CHUTE
FURNACE WATER TUBE PANEL
FEEDER
CAST IRON BLOCK OVERLAY
HYDRAULIC OIL CYLINDER
REFRACTORIES OVERLAY
DRYING GRATE
RIDDLING HOPPER & CHUTE
AIR PLENUM
COMBUSTION GRATE
AUXILIARY FUEL BURNER
DOUBLE DUMPER
RIDDLING CONVEYOR
BURN-OUT GRATE
MAIN ASH CHUTE

Figure 3. Riley-Takuma MSW Stoker Grate

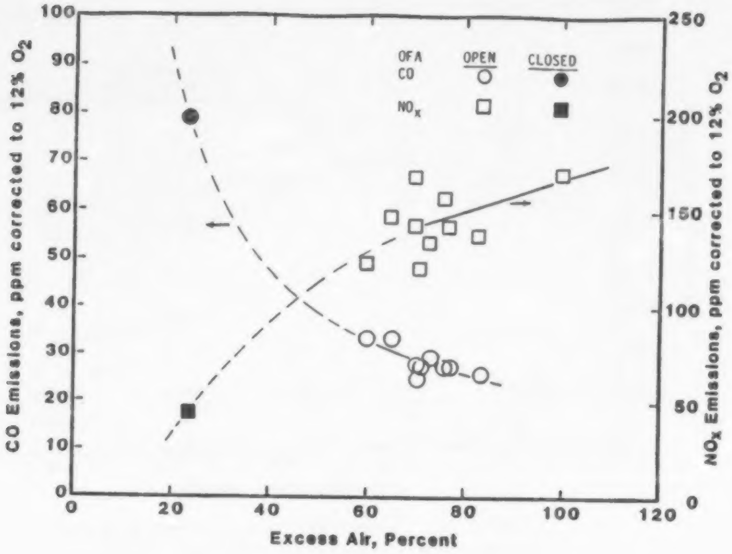


Figure 4. NOx and CO Emissions as a Function of Excess Air, Olmsted Waste to Energy Facility - Economizer Exit

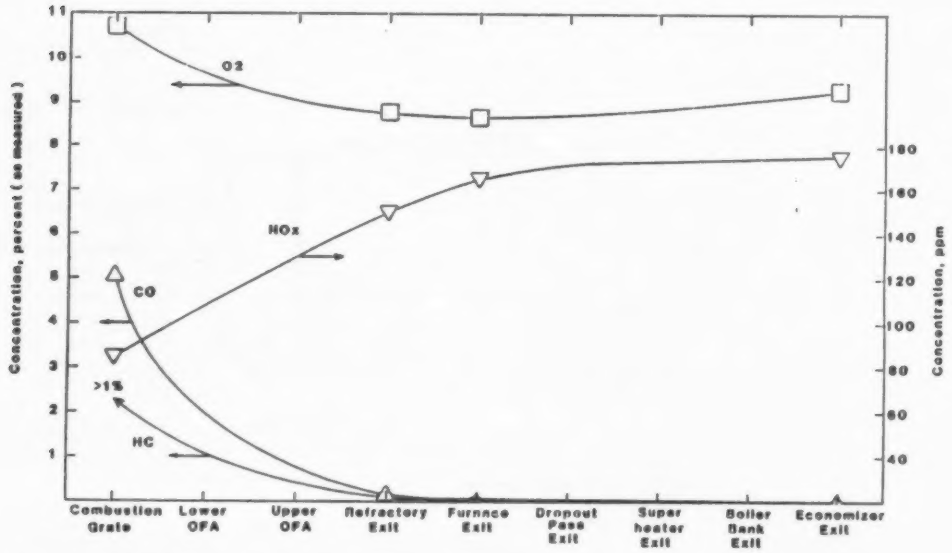


Figure 5. Furnace Gas Composition History Through the Olmsted Waste to Energy Facility During Normal Full Load Operation

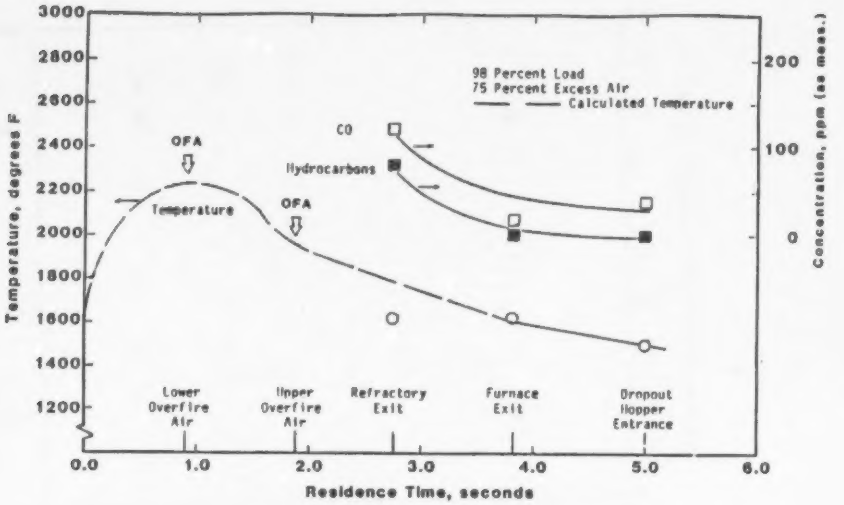


Figure 6. Temperature and Products of Incomplete Combustion Profiles through Olmsted Waste to Energy Facility

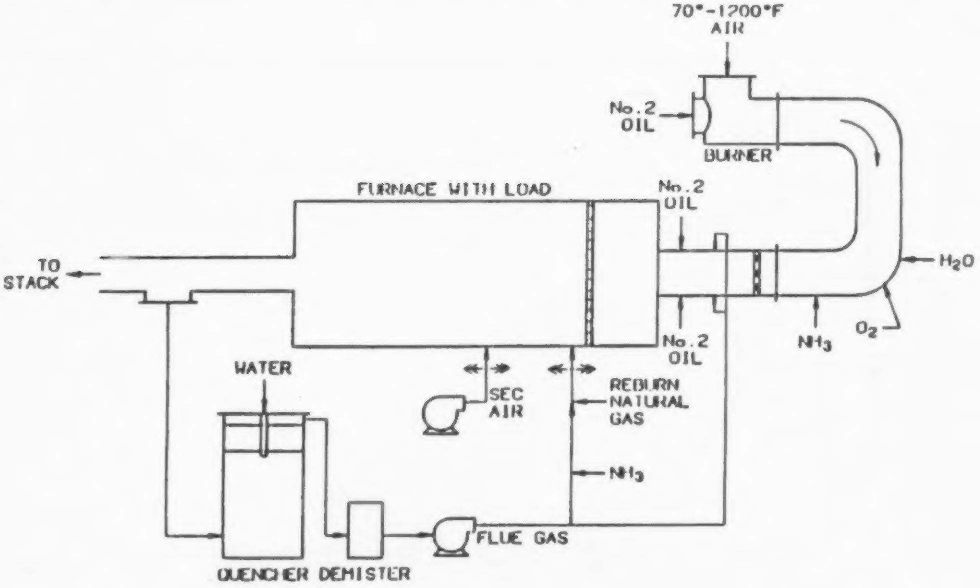

70°-1200°F AIR
No.2 OIL
BURNER
FURNACE WITH LOAD
No.2 OIL
TO STACK
H_2O
O_2
NH_3
No.2 OIL
WATER
SEC AIR
REBURN NATURAL GAS
NH_3
FLUE GAS
QUENCHER
DEMISTER

Figure 7. Schematic of IGT's Pilot-Scale Facility

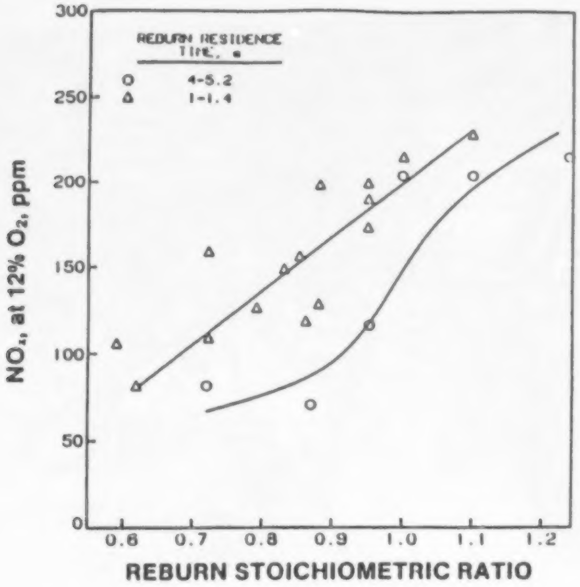


Figure 8. The Effect of Reburn Zone Stoichiometric Ratio on NOx Emissions in IGT Pilot Unit

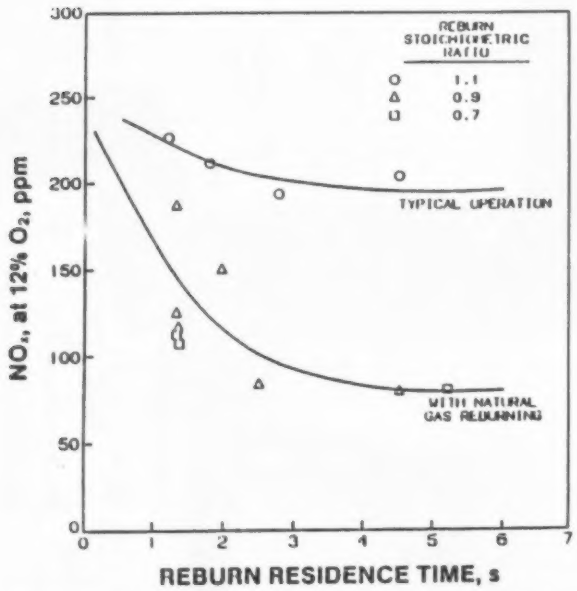


Figure 9. The Effect of Reburn Zone Residence Time on NOx Emissions in IGT Pilot Unit

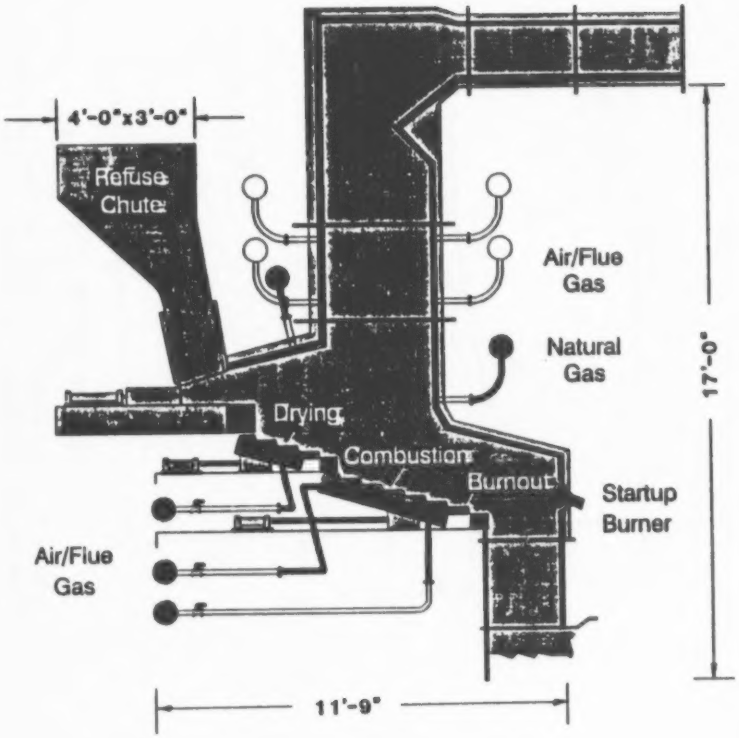

4'-0"x3'-0"
Refuse Chute
Air/Flue Gas
Natural Gas
17'-0"
Drying
Combustion
Burnout
Startup Burner
Air/Flue Gas
11'-9"

Figure 10. Riley Pilot MSW Combustion Facility

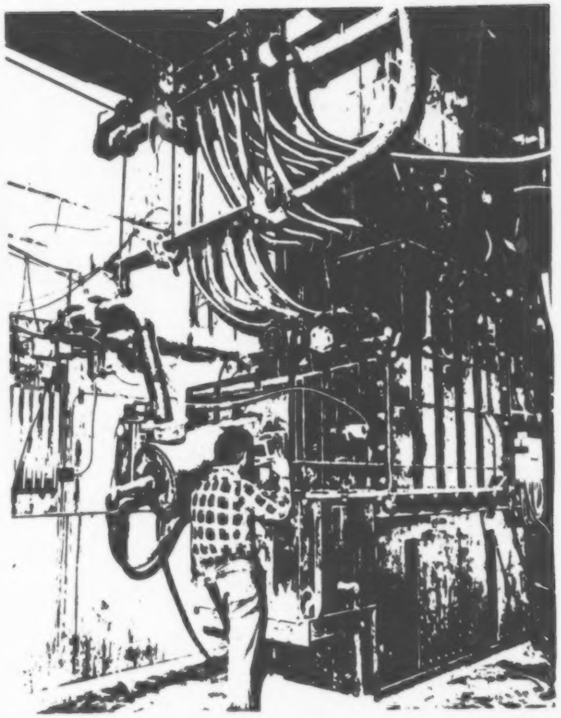
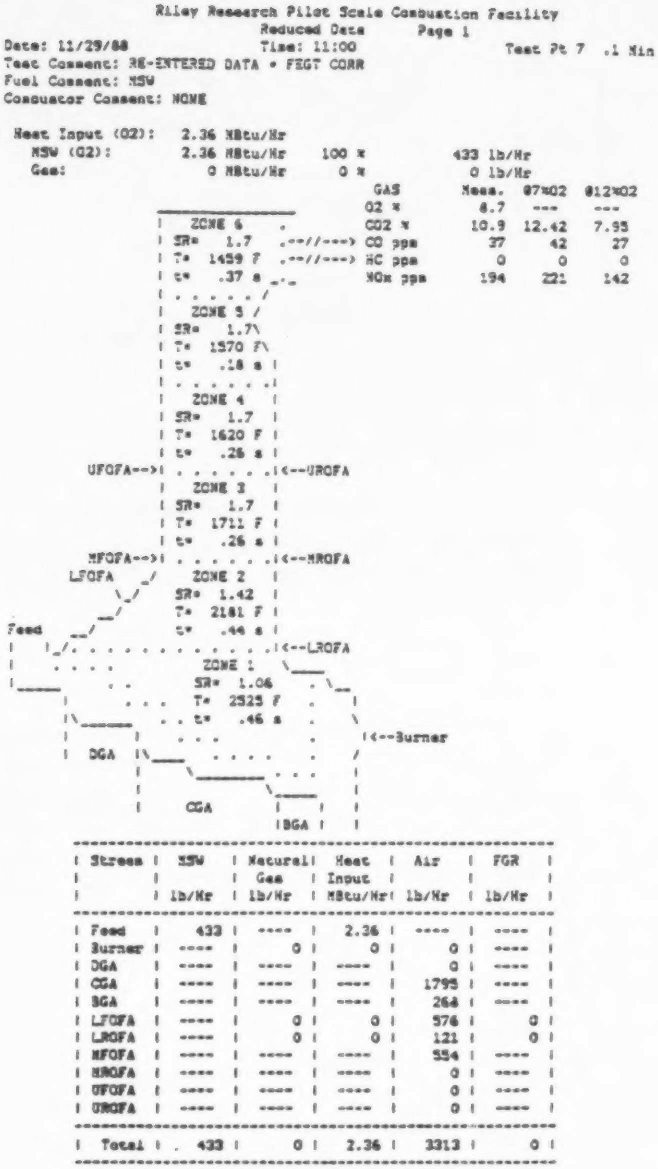


Figure 11. Riley Pilot MSW Combustion Facility - Combustor Section

Reproduced from best available copy.



```
                 Riley Research Pilot Scale Combustion Facility
                             Reduced Data      Page 1
Date: 11/29/88               Time: 11:00                 Test Pt 7  .1 Min
Test Comment: RE-ENTERED DATA • FEGT CORR
Fuel Comment: MSW
Combustor Comment: NONE

 Heat Input (O2):   2.36 MBtu/Hr
   MSW (O2):        2.36 MBtu/Hr    100 %          433 lb/Hr
   Gas:                0 MBtu/Hr      0 %            0 lb/Hr
                                          GAS       Meas.  @7%O2   @12%O2
                 _________________       O2 %         8.7   ---     ---
                  |   ZONE 6     .       CO2 %       10.9  12.42   7.95
                  | SR=   1.7   .--//---> CO ppm       37     42     27
                  | T=  1459 F  .--//---> HC ppm        0      0      0
                  | t=   .37 s _.-_      NOx ppm      194    221    142
                  | . . . . . . /
                  |   ZONE 5 /
                  | SR=    1.7\
                  | T=  1570 F\
                  | t=   .18 s |
                  | . . . . . .|
                  |   ZONE 4   |
                  | SR=   1.7  |
                  | T=  1620 F |
                  | t=   .26 s |
          UFOFA-->| . . . . . .|<--UROFA
                  |   ZONE 3   |
                  | SR=   1.7  |
                  | T=  1711 F |
                  | t=   .26 s |
          MFOFA-->| . . . . . .|<--MROFA
        LFOFA   _/    ZONE 2   |
             \_/    SR=  1.42  |
            __/     T=  2181 F |
Feed     __/        t=   .44 s |
|    |_/. . . . . . . . . . . .|<--LROFA
|     . . . .          ZONE 1   \___
|_____      . .       SR=  1.06    . \__
      |        . . .  T=  2525 F   .    |
      |\______    . . t=   .46 s   .    \
      |       |     . . .          .     |<--Burner
      |  DGA  |\___    . . . .     .    /
              |    \________ . . .      |
              |             \____       |
              |     CGA     |    |      |
                            |BGA |      |

        -------------------------------------------------------
        | Stream  |  MSW   | Natural|  Heat  |  Air   |  FGR   |
        |         |        |  Gas   | Input  |        |        |
        |         | lb/Hr  | lb/Hr  |MBtu/Hr | lb/Hr  | lb/Hr  |
        -------------------------------------------------------
        | Feed    |    433 |  ----  |   2.36 |  ----  |  ----  |
        | Burner  |  ----  |      0 |      0 |      0 |  ----  |
        | DGA     |  ----  |  ----  |  ----  |      0 |  ----  |
        | CGA     |  ----  |  ----  |  ----  |   1795 |  ----  |
        | BGA     |  ----  |  ----  |  ----  |    264 |  ----  |
        | LFOFA   |  ----  |      0 |      0 |    576 |      0 |
        | LROFA   |  ----  |      0 |      0 |    121 |      0 |
        | MFOFA   |  ----  |  ----  |  ----  |    554 |  ----  |
        | MROFA   |  ----  |  ----  |  ----  |      0 |  ----  |
        | UFOFA   |  ----  |  ----  |  ----  |      0 |  ----  |
        | UROFA   |  ----  |  ----  |  ----  |      0 |  ----  |
        -------------------------------------------------------
        |  Total  |    433 |      0 |   2.36 |   3313 |      0 |
        -------------------------------------------------------
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Figure 12. Typical Computer Output from
Riley Pilot Unit - Baseline Testing

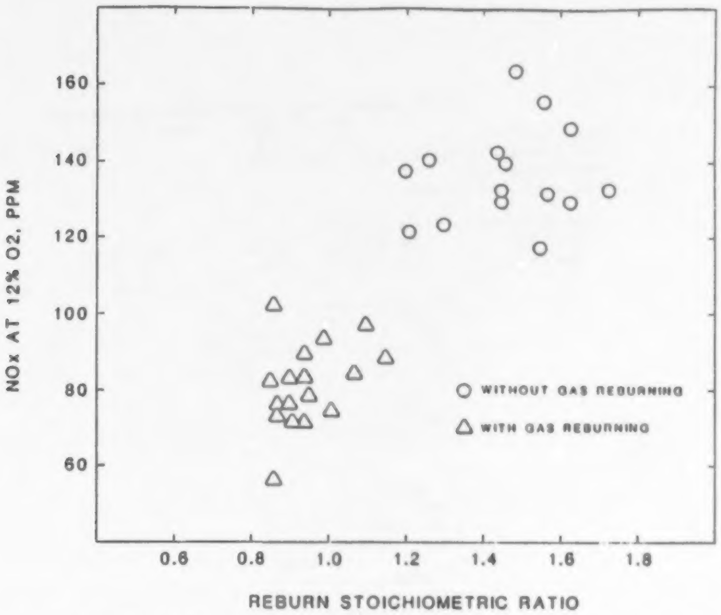

Figure 13. The Effect of Reburn Zone Stoichiometric Ratio on NOx Emissions in Riley Pilot Unit

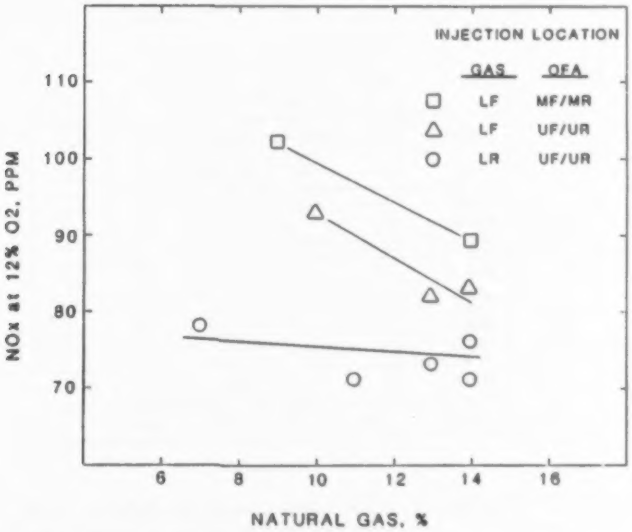

Figure 14. The Effect of Natural Gas Quantity on NOx Emissions in Riley Pilot Unit

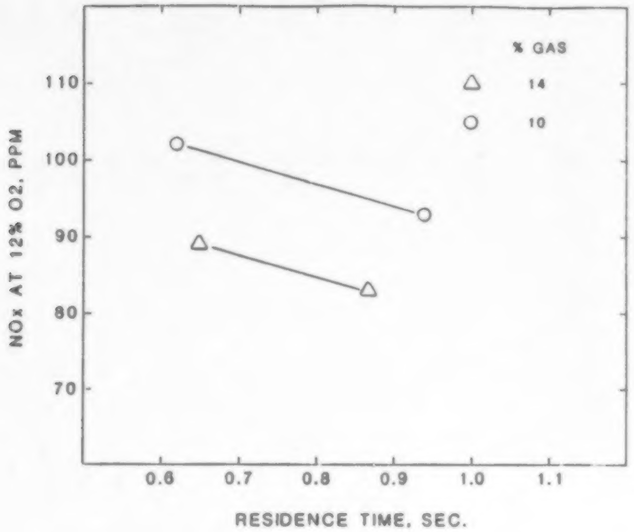

Figure 15. The Effect of Reburn Zone Residence Time on NOx Emissions in Riley Pilot Unit - Lower Front Gas Injection

Table I

COMPARISON OF IGT PILOT DATA
WITH FIELD DATA - BASELINE TESTING

	Baseline Field Test Unit	IGT Furnace Simulator
Test	Typical	Typical
Combustion Products (1)		
O_2, %	7.9	7.9
CO_2, %	10.2	9.8
N_2, %	71.2	70.7
H_2O, %	10.7	11.6
NO_x, PPM	130	100-300
Reburn Zone Temp., °F	~2220 (2)	1950-2400
Reburn Zone Residence Time, sec.	1.0-3.0	1.0-4.5

(1) Wet basis

(2) Estimated from actual measurements of FEGT

TABLE II

TYPICAL FUEL ANALYSIS COMPARISON

	Olmsted County Raw MSW	Riley Unit Processed MSW
Moisture, %	3.35	18.19
Volatile Matter, %	33.86	57.90
Fixed Carbon, %	16.22	11.70
Ash, %	46.57	12.21
Sulfur, %	0.75	0.21
Carbon, %	32.00	34.49
Hydrogen, %	3.44	4.48
Nitrogen, %	0.95	0.35
Oxygen, %	12.94	30.07
HHV, Btu/lb (as rec'd.)	6037	5447
Paper, %	70.0	75.8
Plastic, %	15.0	6.0
Miscellaneous, %	10.0	18.2

TABLE III

COMPARISON OF RILEY PILOT DATA WITH FIELD DATA - BASELINE TESTING

	Field Test Unit	Riley Pilot Unit
Test	21	7
Load, MBtu/hr	37.5	2.36
Excess Air, %	73	70
OFA Flow, %	34	38
OFA Configuration	Std.	Std.
Combustion Products		
O_2, %	9.3	8.7
CO_2, %	10.1	10.9
CO, PPM	29	27
THC, PPM	0	0
NO_x , PPM	134	142
Reburn Zone Temp., °F (1)	2220	2181
Residence Time to Furnace Exit, sec.	~3.8	~2.0

(1) Estimated from actual measurements of FEGT.

Table IV

RILEY PILOT MSW COMBUSTION FACILITY
GAS REBURNING TEST RESULTS

	Stoichiometry					Injection Location			PPM @ 12% 02			
Test	Grate	Reburn	Total	% FGR	% NG	OFA	FGR	NG	NOx	CO	THC	% NOx Reduction
7(1)	1.06	1.42	1.70	0	0	MF/LF/LR	-	-	142	27	0	-
37	1.26	1.10	1.48	13	13	UF/UR	LF	LF	97	25	2	32
38	1.18	1.01	1.48	15	15	"	"	"	74	60	0	48
39	0.95	0.86	1.27	15	10	"	"	"	56	106	5	60
40	0.97	0.87	1.28	13	10	"	"	"	76	32	1	46
41	1.04	0.90	1.32	15	14	"	LR	LR	76	82	4	46
42	1.05	0.91	1.34	13	14	"	"	"	71	98	6	50
43	1.05	0.94	1.37	15	11	"	"	"	71	84	1	50
44	1.36	1.15	1.69	13	15	"	LF	LF	88	93	0	38
45	1.09	0.94	1.37	15	14	"	"	"	83	29	1	42
46	1.10	0.99	1.45	15	10	"	"	"	93	31	1	35
47	0.95	0.86	1.31	15	9	MF/MR	"	"	102	35	2	28
48	1.09	0.94	1.43	15	14	MF/MR	"	"	89	26	1	37
49	0.97	0.85	1.29	17	13	UF/UR	LF/LR	LF	82	73	4	42
50	1.31	1.07	1.61	18	19	"	"	LF/LR	84	33	1	41
51	1.03	0.90	1.35	17	13	"	"	LF/LR	83	19	1	42
52	1.02	0.95	1.44	17	7	"	"	LR	78	25	1	45
53	0.99	0.87	1.31	17	13	"	"	LR	73	26	1	49

(1) Typical Baseline Test

APPLICATION OF LOW NO_x PRECOMBUSTOR TECHNOLOGY TO THE INCINERATION OF NITROGENATED WASTES

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ABSTRACT

A 0.6 MW (2,000,000 Btu/hr) precombustion chamber burner/package boiler simulator facility, designed for in-furnace nitrogen oxide (NO_x) control and high combustion efficiency, has been evaluated for high nitrogen content fuel combustion/waste incineration application. The 250 to 750 ms residence time precombustion chamber burner, using air staging and in-furnace natural gas reburning, yields up to four stoichiometric zones.

During initial facility evaluation, natural gas, doped with ammonia (NH_3) to yield a 5.8 percent fuel nitrogen content, and No. 2 distillate fuel oil, doped with pyridine (C_5H_5N) to yield a 2.0 percent fuel nitrogen content, were used to simulate high nitrogen content fuel/waste mixtures. Minimum nitric oxide (NO) emission levels of 160 and 110 ppm (corrected to 0 percent oxygen, O_2) were achieved for the natural gas and fuel oil tests, respectively. These results correspond to approximately 85 percent reduction in NO_x emissions compared to uncontrolled emissions from a conventional burner mounted on a 0.7 MW (2,500,000 Btu/hr) commercial package boiler. Carbon monoxide (CO) emissions for both low NO_x tests were less than 35 ppm, indicating combustion efficiencies (CEs) greater than 99 percent. Pyridine destruction efficiency (DE) was greater than 99.99 percent.

Subsequently, an investigation examining the incineration characteristics of a nitrogenated pesticide, containing dinoseb (2-sec-butyl-4,6 dinitrophenol) in an organic solvent, was

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conducted on the low NO_x facility. The dinoseb formulation contained 6.4 percent nitrogen. NO emissions without any in-furnace NO_x control strategy exceeded 4400 ppm (0 percent O_2). When NO_x controls, in the form of air staging and natural gas reburning, were employed, these emissions were reduced to below 150 ppm. CO emissions were always less than 25 ppm. Dinoseb DE was greater than 99.99 percent and particulate emissions were less than the RCRA limit of 180 mg/dsm^3. Several common products of incomplete combustion (PICs) were identified in the exhaust gases at concentrations typically less than 10 ppb.

INTRODUCTION

Oxides of nitrogen (NO_x) are formed during combustion by the oxidation of atmospheric nitrogen (N_2) and nitrogen contained in the fuel. Nitrogen dioxide (NO_2) is a toxic gas that the U.S. Environmental Protection Agency (EPA) has designated as a criteria pollutant because of its adverse effects on human health.(1) NO_x emitted from stationary combustion sources contribute to the degradation of air quality as well as to acid deposition and forest damage.(2) Increasing levels of atmospheric nitrous oxide (N_2O) have also been measured. Although the sources of this increase have not been determined, these increasing levels have been predicted to contribute to both a decline in stratospheric ozone concentrations and an increase in global climate warming.(3)

Unlike sulfur oxide (SO_x) emissions, NO_x emissions have been increasing in recent years.(4) While coal- and oil-fired utility and industrial boilers account for over half of these NO_x emissions, only 15 percent of these stationary sources are regulated by EPA's New Source Performance Standards (NSPS).(5) The remaining sources must be addressed with retrofit technologies if significant NO_x emission reduction is to be realized. Another NO_x control problem is posed by the incineration of high nitrogen content wastes in hazardous waste incinerators and industrial boilers. While incineration of these materials may not constitute a significant increase in the overall national NO_x emission levels, individual plant emissions may be sufficient to result in a local NO_x problem thus preventing on-site thermal destruction from being permitted. With thermal destruction becoming an increasingly attractive alternative to landfill storage of wastes, there continues to be a need for developing high efficiency, low NO_x combustion technologies. Additionally, incinerator operating conditions which maximize waste destruction are typically those that promote the formation of NO_x.

NO_x species are formed in practical combustion systems by high temperature thermal fixation of atmospheric nitrogen (N_2, source of thermal NO_x)(6) and by oxidation of nitrogen chemically bound in the fuel (source of fuel NO_x).(7) Thermal NO_x can be reduced by decreasing peak flame temperatures. Fuel NO_x, not as strongly dependent on temperature, is very sensitive to reactant stoichiometry. Fuel-rich conditions promote N_2 formation over nitric oxide (NO) formation. Thus, many of the NO_x control technologies currently in use involve modifications of the combustion process to reduce peak flame temperatures and create fuel-rich conditions by reducing fuel and oxidizer mixing rates. These modifications, however, frequently result in reduced combustion efficiency (CE) and increased vessel wall corrosion and ash deposition. Furthermore, practical constraints, such as burner and boiler sizes, limit the effectiveness of NO_x control by combustion modification.

In-furnace NO_x control technologies currently in use, including reduced air preheat, load reduction, low excess air, flue gas recirculation, overfire air, deep air staging, fuel staging (or reburning), and various low-NO_x burner systems, can reduce NO_x emissions by 20 to 80 percent. While these technologies are sufficient to meet current NSPS requirements, new technologies will be required if more stringent NO_x emissions regulations are enacted. EPA has been involved in the development of two evolving NO_x control technologies: the precombustion chamber burner and reburning. These two combustion modification strategies provide alternatives to expensive post-combustion NO_x control technologies, such as selective catalytic reduction which is being utilized extensively in Japan and West Germany. The goal of this experimental program was to utilize the precombustion chamber burner and reburning concepts in developing a low-NO_x, high efficiency combustion system that is practical for both new and retrofit applications.

BACKGROUND

Precombustion Chamber Burner

The precombustion chamber burner is a staged combustion technology capable of achieving NO_x emissions of less than 0.1 lb (as NO_2)/10^6 Btu (or approximately 90 ppm NO_x), even with high nitrogen content fuels.(8) The burner, described by Englund et al.,(8) consists of a primary air and fuel injection system, a large refractory lined precombustion chamber, and a secondary staged air injection section. Fuel and primary air are injected so as to promote rapid mixing in the nearly adiabatic precombustion chamber with a first stage stoichiometry of between 0.6 and 0.8. Residence times between 0.6 and 1.0 sec allow for maximum reduction and conversion of fuel nitrogen species to N_2 in the fuel-rich precombustion chamber. First-stage combustion gases exit the burner through a convergent transition section which minimizes both radiative heat loss to the boiler and back-mixing of the secondary air. The transition section between the burner and boiler is water-cooled to reduce combustion gas temperatures before further air addition and thus minimize the formation of thermal NO_x.

The precombustion chamber burner has been tested on a full-scale (16 MWt) crude-oil-fired steam generator used for thermally enhanced oil recovery (TEOR).(9) A 30-day continuous monitoring test using heavy residual oil demonstrated the burner's ability to maintain a nominal NO_x emission of 70 ppm and high combustion efficiency. During burner optimization testing, NO_x, carbon monoxide (CO), and smoke emissions were measured over a range of first-stage stoichiometries. These data indicate the sensitivity of NO_x emission to first-stage stoichiometry and the good hydrocarbon burnout characteristics of the burner.

A test designed to demonstrate the potential for using this burner for nitrogenated waste incineration was performed at EPA's Air and Energy Engineering Research Laboratory (AEERL). A pilot- scale (0.6 MWt) precombustion chamber burner was used to incinerate a surrogate nitrogenated waste mixture of 9.1 percent (by volume) pyridine (C_5H_5N) in No. 2 distillate fuel oil. NO_x emissions of less than 100 ppm were maintained, with greater than six nines (99.9999%) destruction of pyridine being achieved. The relative NO_x emissions, with and without pyridine addition, indicate that less than 1 percent of the fuel nitrogen was converted to NO. This preliminary result sparked interest in utilizing the precombustion chamber burner for low NO_x, high efficiency incineration.

While the precombustion chamber burner has been demonstrated successfully in pilot and full-scale tests, its large size and heavy refractory composition make it impractical for most boiler retrofit applications. Reducing the burner size results in insufficient first-stage residence time to fully convert fuel nitrogen to N_2. However, further NO_x control can be achieved by further fuel and air staging (reburning) in the boiler. Current research is investigating the use of light weight refractories to provide improved response to load changes.

Reburning

Reburning is an in-furnace NO_x control technology in which portions of the fuel and combustion air streams are diverted downstream of the primary flame. In this way, the combustor has three distinct zones: a fuel-lean primary zone, a fuel-rich reburning zone, and a fuel-lean burnout zone. NO_x reduction via reburning occurs both by combustion of a portion of the fuel under fuel-rich stoichiometries (conditions not promoting NO_x formation), and chemical destruction mechanisms involving secondary flame radical reactions with NO, resulting in N_2 formation. An EPA study (10) has shown that 50 percent NO_x reduction is possible with 15 to 20 percent of the fuel used for reburning. At low primary NO_x levels, however, a nitrogen-free reburning fuel (such as natural gas) must be used to achieve 50 percent reduction. Reburning can be used in conjunction with other NO_x control schemes to yield lower NO_x emissions. However, application of reburning often necessitates hardware modifications to the combustor.

LOW NO_x EXPERIMENTAL FACILITY

The pilot-scale experimental facility, shown schematically in Figure 1, consists of a vertical precombustion chamber low-NO_x burner and a horizontal package boiler simulator. The precombustion chamber consists of a primary fuel and air injection module, several 0.25 m long spool modules with 0.51 m inside diameter (I.D.), and a convergent elbow module. The modular design of the precombustor permits variation in nominal first-stage residence time between 250 and 750 ms. The modules have a thick refractory wall lining to minimize heat loss and, thus, maintain high temperatures that promote conversion of fuel nitrogen to N_2 under fuel-rich stoichiometries. To achieve rapid mixing in the precombustion chamber, the primary fuel is injected through a divergent nozzle, and the primary air, which is not preheated, is passed through fixed swirl vanes. The convergent elbow module minimizes back-mixing of combustion gas and radiation losses to the boiler. A water-cooled transition module, 0.25 m I.D., cools the combustion gas before secondary air addition to minimize thermal NO_x generation.

The pilot-scale boiler simulator is rated at 0.9 MW thermal input. The boiler's radiant section is horizontal, 0.6 m I.D., 3.0 m long, and cooled with Dowtherm G heat transfer fluid. Combustion gas exits the boiler through a vertical stack. The burner/boiler transition section allows for radial addition of staged air. Additionally, the boiler's front face has two ports for addition of staged (reburn) fuel at an angle of 45 degrees off axis and six axial ports for the addition of burnout air. This design allows for reburning application from the boiler front face, with aerodynamic separation of the fuel-lean, fuel-rich, and fuel-lean zones in the boiler.

The experimental facility is designed for independent control and measurement of each fuel, fuel dopant (if any), and air stream. Stack gas species are measured by continuous emissions monitors (CEMs). These monitors include measurement of NO, NO_x, O_2, CO, CO_2, and total unburned hydrocarbons (THC). All data are reported corrected to 0 percent O_2 dry basis.

BURNER PERFORMANCE EVALUATION

Natural gas, doped with ammonia (NH_3) to yield a 5.8 percent fuel nitrogen content, and No. 2 distillate fuel oil, doped with pyridine (C_5H_5N) to yield a 2 percent fuel nitrogen content, were used to simulate high nitrogen content fuel/waste mixtures. In these tests, the shortest burner configuration, corresponding to a first-stage nominal residence time of 250 ms, was evaluated. A 0.7 MW North American fire-tube package boiler was used to provide conventional burner results for comparison with the multistaged burner results. This boiler is a three-pass unit with a continuous service rating of 0.3 kg of steam per second (2400 lb/hr). Its size and thermal characteristics are similar to those of the package boiler simulator.(11)

Burner baseline performance (air staging) and burner operation with reburning (fuel staging) were evaluated. The parameters affecting the NO_x emissions from the facility without reburning are fuel nitrogen content, combustion gas residence time in the prechamber, first-stage stoichiometry, and exhaust stoichiometry. The residence time of combustion gas in the burner depends on precombustion chamber length, load, and stoichiometry. The nominal load was 0.6 MW. The exhaust stoichiometry was kept at a nominal value of 15 percent excess air. First-stage stoichiometry was optimized for each parametric test sequence.

Burner Stoichiometry Variation

First-stage stoichiometry was varied by changing the primary air flow. Secondary radial air was adjusted to maintain 15 percent excess air. The results are plotted in Figure 2. The curves indicate a strong sensitivity of stack NO to changes in burner stoichiometry. For the NH_3/natural gas tests, a minimum NO emission of 315 ppm occurred at a burner stoichiometry of about 0.78. For the C_5H_5N/fuel oil tests, a minimum of 190 ppm occurred at a burner stoichiometry of 0.65. By comparison, similar tests using the North American boiler produced NO emissions of 1000 ppm when firing the 5.8 percent nitrogen NH_3/natural gas fuel at 15 percent excess air. NO emissions of 765 ppm resulted when firing the 2 percent nitrogen C_5H_5N/fuel oil mixture at 15 percent excess air. Thus, the low NO_x burner reduced NO emissions by 68 percent for the NH_3/natural gas fuel and by 75 percent for the C_5H_5N/fuel oil mixture.

Excess Air Variation

The effect of excess air variation on stack NO is shown in Figure 3. As expected, excess air had a much stronger effect in the conventional North American boiler tests than in the low NO_x burner tests. While reducing excess air did provide some NO reduction with the low NO_x burner, maintaining an exhaust excess air level of 15 percent is important for achieving high combustion efficiency.

Load Variation

The effect of load reduction on stack NO is shown in Figure 4. As load was decreased from a nominal condition of 0.6 MW to 65 percent of nominal, the stack NO concentration dropped by 20 to 25 percent in the low NO_x burner tests. With a conventional burner, NO emissions are reduced only slightly with burner derating, due to decreased air/fuel mixing intensity. However, with the low NO_x burner, the effect is much greater because load reduction corresponds to an increase in first-stage residence time and, thus, a decrease in NO emission. Reducing load by 35 percent increased burner residence time from 250 to 385 ms.

Fuel Nitrogen Variation

In addition to the base case tests, fuel nitrogen content was varied between 0 and 5.8 percent and 0 and 5.0 percent for the NH_3/natural gas and C_5H_5N/fuel oil tests, respectively. The effect of fuel nitrogen variation is shown in Figure 5. As expected exhaust NO levels increase with increasing fuel nitrogen content. Results from the conventional North American boiler were much more sensitive to this effect. These results demonstrate the precombustion chamber burner's ability to reduce fuel nitrogen to N_2 even at reduced size (250 ms). The full size (600 to 800 ms) precombustion chamber burner produces NO emissions even less sensitive to fuel nitrogen content.(8)

Reburning Tests

For these tests, total boiler load (0.6 MW, 2,000,000 Btu/hr) was held constant while 35 percent of the fuel was diverted from the primary fuel injector to two secondary injectors. The reburn fuel (undoped natural gas) was added through two ports in the boiler front face at an angle of 45 degrees off axis, using water-cooled injectors (see Figure 1). Staged air to complete primary fuel combustion was added radially into the transition section. Burnout air for the reburn fuel was added axially near the boiler wall through six axial ports on the boiler front face. Thus, a four-stage combustion process was established, consisting of a fuel-rich burner zone and three boiler zones characteristic of reburning (i.e, fuel-lean, fuel-rich, fuel-lean). The stoichiometry in the third stoichiometric zone (SR3, the fuel-rich reburning zone in the boiler) is critical in this NO_x control process.

The C_5H_5N/fuel oil and NH_3/natural gas results are given in Figure 6. NO emissions decrease due to both primary NO destruction and primary combustion gas dilution. Two second-stage stoichiometries (SR2) were established (1.1 and 1.0), with 35 percent fuel staging (reburning). The exhaust NO levels were reduced to 120 ppm (from 190 ppm) at a

SR2 of 1.1 (and a SR3 of 0.76) and to 110 ppm at a SR2 of 1.0 (and a SR3 of 0.69) for the C_5H_5N/fuel oil tests. Similarly, NO emissions were reduced to 195 ppm (from 315 ppm) at a SR2 of 1.1 and 160 ppm at a SR2 of 1.0 for the NH_3/natural gas tests. Note that dilution accounts for most of the decreases measured. Due to less distinct stoichiometric zones than typically established in reburning applications, the NO reduction by fuel staging was not quite as great as that obtainable when the staged fuel is injected farther downstream of the fuel-lean second-stage zone.(11) However, the configuration used in these tests requires no additional boiler penetrations other than modifications to the boiler front face. In addition, complete destruction of the primary fuel/waste stream appears to be ensured by providing all of the required primary combustion air prior to entry into the boiler.

Burner performance evaluation results indicate that relatively low NO_x emission levels are possible with a shortened precombustion chamber burner provided the first-stage stoichiometry is optimized and a post-flame NO_x control technology like reburning is used. CO emissions, for all the tests performed during burner performance evaluation, were less than 35 ppm, indicating that combustion efficiencies attained were greater than 99 percent.

NITROGENATED WASTE INCINERATION

Subsequent to the burner evaluation tests, an investigation to examine the incineration characteristics of a nitrogenated pesticide, containing dinoseb (2-sec-butyl-4,6 dinitrophenol), in an organic solvent, was conducted on the low NO_x burner facility. The burner was configured with all its modular sections in place so as to maximize the first stage residence time (750 ms). This dinoseb pesticide product formulation contained 6.4 percent nitrogen. An ultimate analysis and analysis from the material data safety sheet are shown in Table 1. Incineration conditions with no NO_x control, with air staging, and with air staging and reburning were evaluated using the low NO_x burner/package boiler simulator. The North American boiler was not used for these tests. Natural gas was used as the reburn fuel and was added in addition to a fixed primary load of 0.6 MW (2,000,000 Btu/hr). This increase in total load (approximately 32%) differs from the procedure used during the burner evaluation tests where total load was held constant.

A Source Assessment and Sampling System (SASS) train in conjunction with GC/MS analysis was used to characterize emissions of dinoseb and semi-volatile organic products of incomplete combustion (PICs). A Volatile Organic Sampling Train (VOST) in conjunction with GC/MS analysis was used to characterize emissions of volatile PICs. Dinoseb recovery was characterized by spiking 100 g XAD-2 resin with standard dinoseb solutions in dichloromethane. All XAD-2 and particulate filter samples were Soxlet extracted in dichloromethane and methanol, concentrated by Kederna-Danish evaporation, and analyzed by GC/MS. Prior to the incineration tests, scoping tests were carried out to determine the maximum dinoseb product concentration in No. 2 distillate fuel oil for stable operation. During these tests, successively increasing concentrations of dinoseb product in fuel oil were incinerated until combustion conditions deteriorated. However, the scoping tests revealed that 100 percent dinoseb product could be stably combusted. Thereafter, the remaining incineration tests were carried out with 100 percent dinoseb product. The experimental matrix describing the tests conducted is shown in Table 2.

Gaseous and Particulate Emissions

Table 3 presents the stoichiometric and reburning parameters and the gaseous and particulate emissions for the dinoseb product incineration tests. All concentrations are presented dry and corrected to 0 percent O_2. Concentrations corrected to 7 percent O_2 (RCRA convention) are presented in parentheses. Test 7 indicates that NO emissions without any combustion modification for NO_x control exceeded 4400 ppm. When NO_x controls in the form of air staging with and without natural gas reburning were applied, these NO emissions were reduced to below 150 ppm. Thus the use of the precombustor concept reduced the NO emissions by approximately 96 percent. It is interesting to note that reburning did not offer any further NO_x reduction over incineration conditions with air staging only. This is likely because the configuration of the experimental facility provided ample first stage residence time for the conversion of fuel nitrogen to N_2 and further allowed secondary air addition at relatively cool temperatures, thus inhibiting the formation of thermal NO. These effects probably provided a low concentration NO pool before the addition of reburning fuel and so inhibited reburning efficiency.(10) It is interesting to note that the NO_x measurements are very similar to those for NO. In fact, the differences are well within instrument error. This addresses our concern that, because of the nitrogenated nature of dinoseb, NO_2 may be preferentially emitted. We see, however, that, consistent with other nitrogen containing fuels tested, NO_2 is typically less than 5 percent of the total NO_x emitted. It is also important to note that corresponding NO emissions from uncontrolled dinoseb product combustion in industrial boilers would likely be somewhat less than that measured in test 7. The high temperature, adiabatic design of the precombustor promotes thermal NO_x formation when operated fuel-lean. This type of operation, however, is comparable to that used in most hazardous waste incinerators (high temperatures, adiabatic, high excess air, high residence times) and so is of practical interest.

The particulate emissions for all tests were below the RCRA limit of 180 mg/dsm^3, and were determined to consist primarily of calcium sulfate and calcium oxide (particulate analyzed by x-ray diffraction). The particulate emission level for dinoseb product incineration with reburning was less than that for dinoseb product incineration without reburning. This may be partially due to increased secondary flame burnout, but is also due to simple dilution by the addition of natural gas reburn fuel and oxidizer. The CO and unburned hydrocarbon (THC) emissions were less than 15 ppm and 5 ppm, respectively, indicating that the combustion efficiencies were in excess of 99 percent.

Dinoseb Destruction Efficiencies and Products of Incomplete Combustion

No dinoseb was detected in any of the concentrated dichloromethane extract combustion emission samples. These combined XAD-2 and particulate filter extracts were analyzed by GC/MS. These results and the results of dinoseb recovery tests are shown in Table 4. These data indicate that, although the extraction method used resulted in low dinoseb recovery (9.39%), destruction efficiencies (DEs) calculated using measured instrument detection limits could be determined to be greater than the 99.99 percent RCRA limit. Low dinoseb recoveries, however, are not unique to these tests. Efforts by Acurex Corporation on samples from another dinoseb campaign [sponsored by the EPA Risk Reduction

Engineering Laboratory (RREL)] and Battelle Columbus Division performing nitrogenated PIC analyses [for the EPA Health Effects Research Laboratory (HERL)] found similar results.

Qualitative PIC emissions, measured by SASS and VOST sampling in conjunction with GC/MS analysis, are shown in Table 5. Results indicate that several common combustion PICs are present and emitted in concentrations typically less than 10 ppb. It is important to note that these analyses include only qualitative identification of volatile and semi-volatile compounds. These categories approximately correspond to compounds with boiling points below 100 °C and those between 100 to 300 °C, respectively. No information is currently available regarding the potential presence of higher molecular weight compounds including polycyclic aromatic hydrocarbons (PAHs) and nitrogenated PAHs.

CONCLUSIONS

Results from the burner evaluation experimental program indicate that a precombustion chamber burner, shortened in length and coupled with reburning, is most effective in minimizing NO_x emissions and is capable of providing an overall NO reduction of approximately 85 percent. These observations were confirmed in the dinoseb tests, where NO_x reductions of approximately 96 percent were obtained.

The reburning hardware modifications used in this study were designed with retrofit feasibility and efficient combustion in mind. In the reburning tests performed during the evaluation phase, staged fuel and air from the front face of the boiler provided a secondary flame for increased primary fuel/waste destruction.

Finally, the results of this program indicate that the precombustion chamber burner technology is capable of incinerating highly nitrogenated wastes with DEs in excess of 99.99 percent, maintaining low NO_x and PIC emissions, and producing combustion efficiencies in excess of 99 percent. This technology may, therefore, be an attractive alternative for the disposal/destruction of highly nitrogenated wastes.

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DISCLAIMER

The research described in this paper has been reviewed by the Air and Energy Engineering Research Laboratory, U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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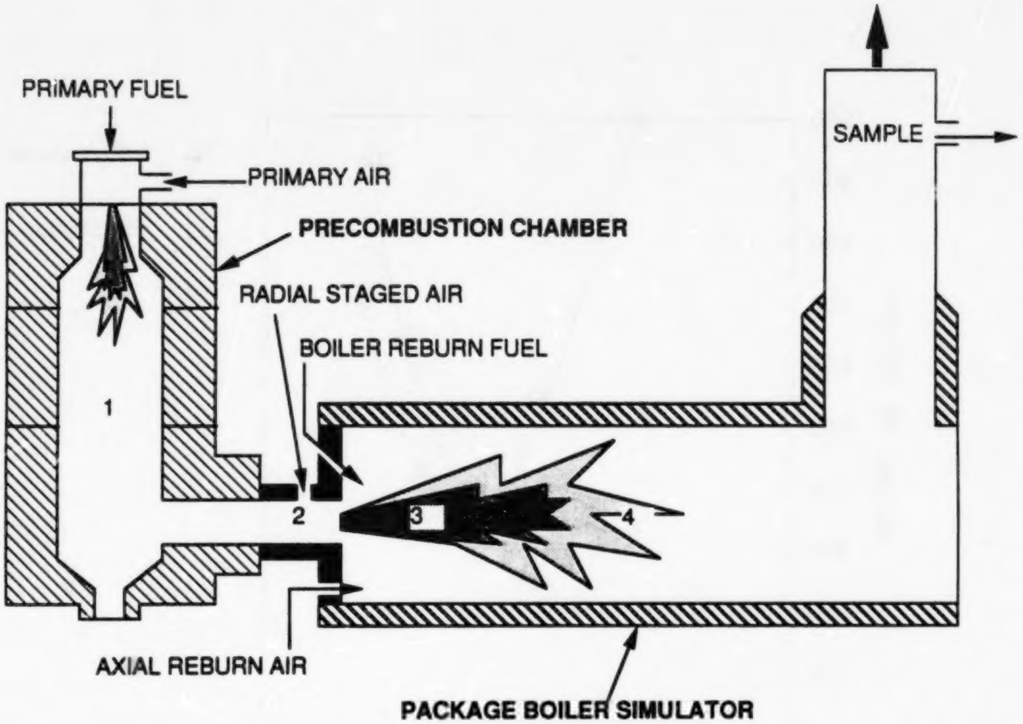
PRIMARY FUEL
PRIMARY AIR
PRECOMBUSTION CHAMBER
RADIAL STAGED AIR
BOILER REBURN FUEL
SAMPLE
1
2
3
4
AXIAL REBURN AIR
PACKAGE BOILER SIMULATOR

Figure 1. EPA pilot-scale combustion research facility consisting of a refractory-lined precombustion chamber and package boiler simulator, with modified air and fuel staging ports.

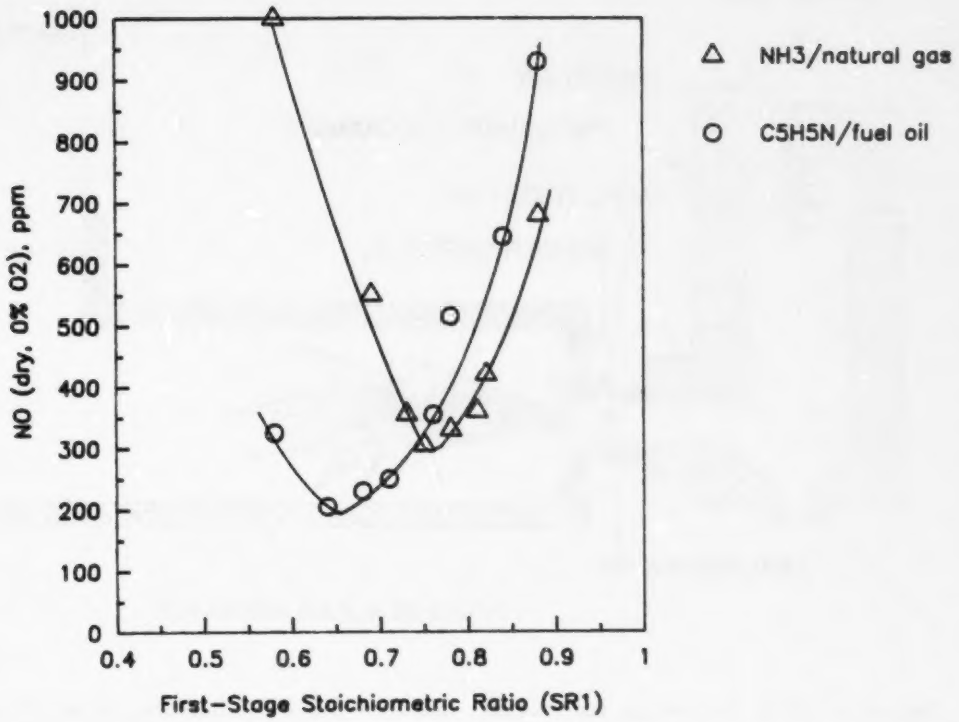

Figure 2. Effect of burner stoichiometry on exhaust NO concentration from tests burning a 5.8 percent fuel nitrogen NH_3/natural gas and a 2 percent fuel nitrogen C_5H_5N/No. 2 distillate fuel oil mixtures.

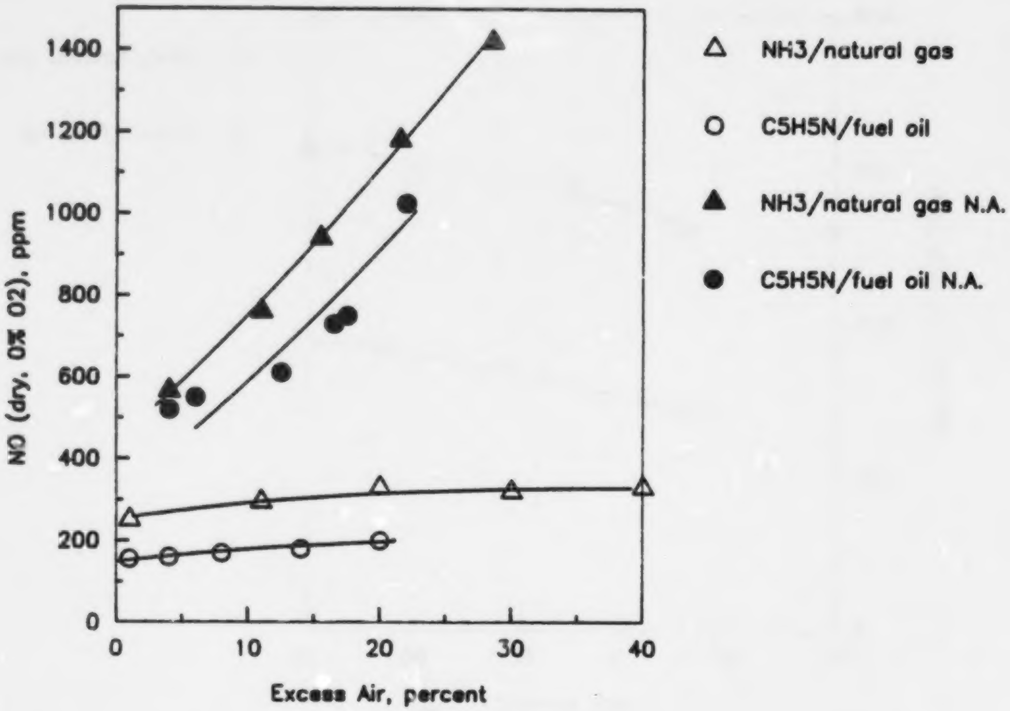

Figure 3. Effect of excess air on exhaust NO concentration from tests burning a 5.8 percent fuel nitrogen NH_3/natural gas and a 2 percent fuel nitrogen C_5H_5N/No. 2 distillate fuel oil mixtures. Curves with open symbols represent data from the low NO_x facility operated at optimum primary stoichiometries as shown in Figure 2. Curves with filled symbols represent corresponding data from the conventional North American (N.A.) boiler.

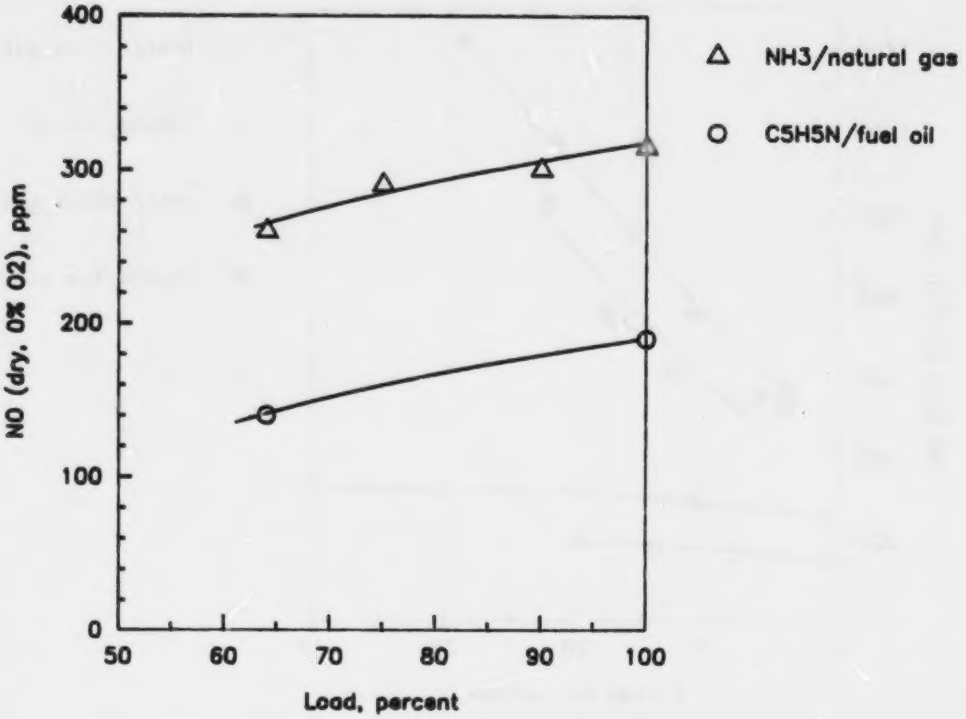

Figure 4. Effect of load variations on exhaust NO concentration from tests burning a 5.8 percent fuel nitrogen NH_3/natural gas and a 2 percent fuel nitrogen C_5H_5N/No. 2 distillate fuel oil mixtures (primary stoichiometries optimized).

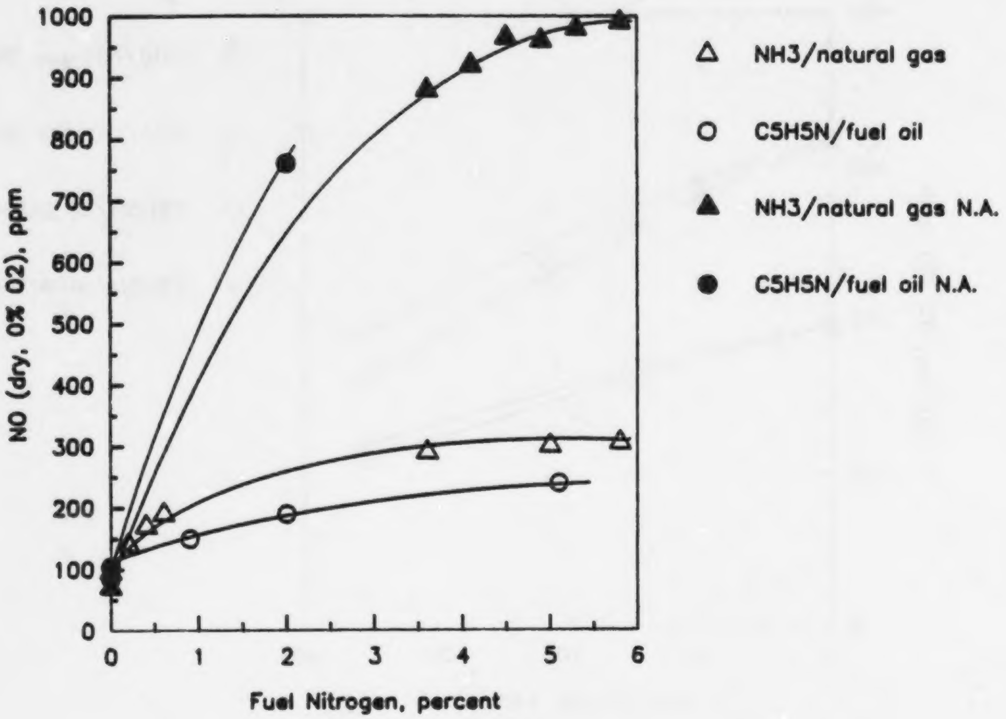

Figure 5. Effect of fuel nitrogen on exhaust NO concentration from tests burning NH_3/natural gas and C_5H_5N/No. 2 distillate fuel oil mixtures. Curves with open symbols represent data from the low NO_x facility (optimal primary stoichiometries). Curves with filled symbols represent corresponding data from the conventional North American (N.A.) boiler.

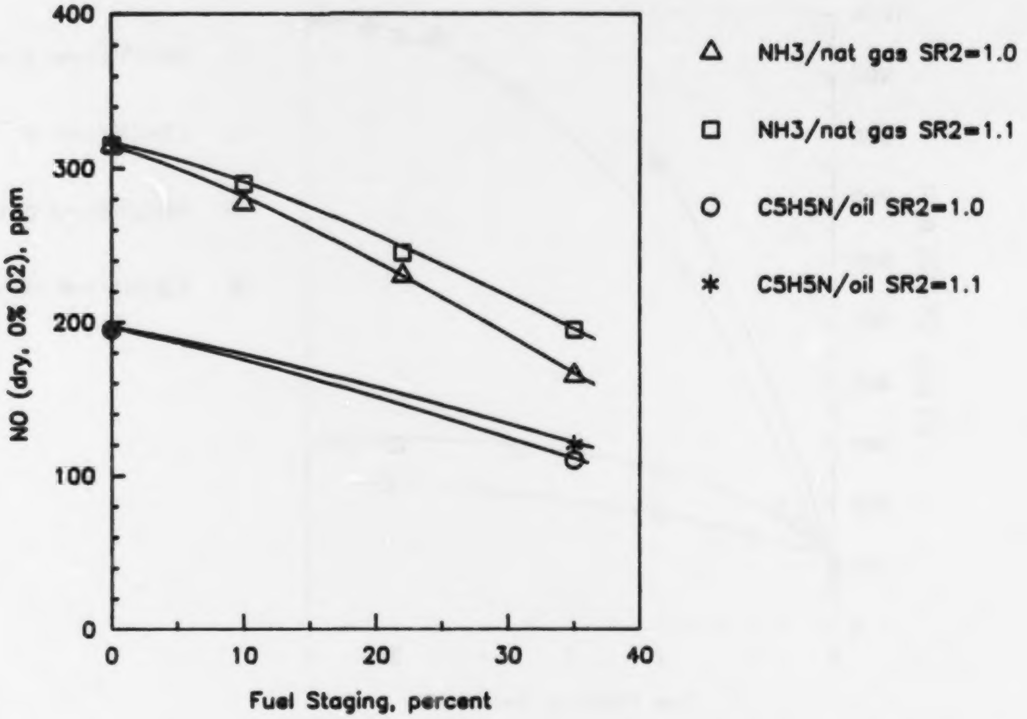

Figure 6. Effect of boiler fuel staging (reburning) on exhaust NO concentration from tests burning a 5.8 percent fuel nitrogen NH_3/natural gas and a 2 percent fuel nitrogen C_5H_5N/No. 2 distillate fuel oil mixtures. Natural gas data at two second stage stoichiometries (primary stoichiometry, SR1 = 0.78), and corresponding oil data at two second stage stoichiometries (primary stoichiometry, SR1 = 0.65) are presented.

TABLE 1

ANALYSIS OF DINOSEB PRODUCT USED FOR INCINERATION TESTS

Dinoseb in organic solvent (dinoseb product)

Analysis from Material Safety Sheet		Ultimate Analysis	
Dinoseb	54.4 %	C	65.01 %
Diesel #2	4.04 %	H	7.27 %
Xylene Range Aromatic	32.5 %	N	6.63 %
		O*	20.45 %
Inert	9.06 %	S	0.35 %
		Ash	0.29 %
		Moisture	0.63 %
		HHV	13,076 Btu/lb

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*Oxygen by difference.

TABLE 2

EXPERIMENTAL TEST PLAN

Burner performance evaluation tests

Test	Condition	NO_x Control	Analyses
A	NH_3/natural gas 5.8% fuel nitrogen content	Vary first stage stoichiometry, excess air, load, fuel nitrogen content, reburning	CEM
B	C_5H_5N/No. 2 distillate fuel oil 2.0% fuel nitrogen content	Same as above.	SASS, CEM

Dinoseb recovery tests*

Test	Dinoseb Spike (ug)	Concentrate Volume (ml)	Analysis Concentration (ng/ul)
1A	100	10	10
1B	100	1	100
1C	1000	1	1000

Dinoseb product incineration tests

Test	Condition	NOx Control	Analyses
2	Combustion blank #2 fuel oil	Air staging	CEM, VOST, SASS
3	Combustion blank #2 fuel oil	Air staging and reburning	CEM, VOST, SASS
4	Dinoseb product scoping test (determine max dinoseb product conc. in No. 2 fuel oil for stable operation)	Air staging	CEM
5	100% dinoseb product	Air staging	CEM, VOST, SASS
6	100% dinoseb product	Air staging and reburning	CEM, VOST, SASS
7	100% dinoseb product	None	CEM

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*For dinoseb recovery tests, standard dinoseb solutions (in dichloromethane) were spiked on 100 g XAD-2 resin, extracted, and concentrated.

TABLE 3

DINOSEB PRODUCT CEM AND PARTICULATE RESULTS*

Test	Condition	NO_x Control	SR1**	SR2	SR3	SR4	R/P %***
2	Combustion blank	Air staging	0.72	1.35	1.35	1.35	N/A
3	Combustion blank	Air staging and reburning	0.62	1.14	0.87	1.20	32.5
5	Dinoseb product	Air staging	0.64	1.23	1.23	1.23	N/A
6	Dinoseb product	Air staging and reburning	0.61	1.08	0.82	1.17	31.4
7	Dinoseb product	None	1.13	1.13	1.13	1.13	N/A

Test	NO (ppm)	NO_x (ppm)	CO (ppm)	CO_2 (%)#	THC (ppm)	Particulate (mg/dsm^3)	Temp1 (°C)##	Temp4 (°C)
2	78 (52)	-	9 (6)	-	-	4.13 (2.75)	-	-
3	89 (59)	-	13 (9)	-	-	5.02 (3.35)	-	-
5	141 (94)	128 (85)	6 (4)	-	2 (1)	151.34 (100.89)	1343	633
6	138 (92)	132 (88)	14 (9)	-	1 (0.7)	81.76 (54.51)	1151	652
7	4401 (2934)	4497 (2998)	13 (9)	-	1 (0.7)	-	708	606

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*Stack emissions corrected to 0% oxygen. Emissions corrected to 7% oxygen are given in parentheses.

**SR1, SR2, SR3, SR4 indicate the stoichiometric ratios calculated at the combustor locations shown in Figure 1.

***R/P indicates gas reburning load/primary load (natural gas added in addition to primary burner load of 2,000,000 Btu/hr). (CEM concentrations have not been corrected for this dilution.)

#CO_2 concentrations are suspect and are not included due to instrument malfunction.

##Temp1, Temp4 indicate approximate gas temperatures (bare thermocouples, near the wall) measured at the combustor positions shown in Figure 1.

TABLE 4

DINOSEB PRODUCT POHC ANALYSES

Dinoseb recovery tests, instrument sensitivity 10 ng/ul

Test	Analysis Concentration (ng/ul)	Measured Concentration (ng/ul)	Percent Recovery
1A	10	ND*	N/A**
1B	100	ND	N/A
1C	1000	93.9	9.39

Incineration tests

Test	Condition	NO_x Control	Dinoseb Consumed (g)	Sample Vol as fraction of Stack Vol
2	Combustion blank	Air staging	0	0.00705
3	Combustion blank	Air staging and reburning	0	0.00276
5	Dinoseb product	Air staging	68130.7	0.00238
6	Dinoseb product	Air staging and reburning	76023.4	0.00275

Test	Potential Max. Dinoseb Conc. in Sample (g, ng/ul)	Dinoseb Conc. Measured in Sample (ng)	DRE Assuming 10 ng/ul Instrument Sensitivity, 100% Recovery	DRE Assuming 10 ng/ul Instrument Sensitivity, 9.39% Recovery
2	0	ND	N/A	N/A
3	0	ND	N/A	N/A
5	162.15, 4,054,000	ND	> 99.9998	> 99.997
6	209.31, 10,466,000	ND	> 99.9999	> 99.999

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*Not detected.
**Not applicable.

TABLE 5

DINOSEB PRODUCT PIC ANALYSES

VOST samples (GC/MS)

Test	Condition	PICs Identified	ng	mg/sm^3	ppb
2A	Comb. blank w/ air staging	Benzene	2	< 0.001	< 1
3A	Comb. blank w/ air staging and reburning	Benzene	37	0.002	< 1
		SO_2	514	0.028	10.7
3B		Benzene	18	0.001	< 1
		SO_2	414	0.022	8.4
5A	Dinoseb product w/ air staging	Benzene	12	0.001	< 1
		Toluene	4	< 0.001	< 1
		Ethylbenzene	4	< 0.001	< 1
		Dodecane	22	0.001	< 1
		Naphthalene	1725	0.091	17.4
5B		Benzene	2	< 0.001	< 1
		SO_2	125	0.007	2.7
6	Dinoseb product w/ air staging and reburning	Benzene	9	0.001	< 1
		Toluene	10	0.001	< 1

SASS samples (GC/MS)

Test	Condition	PICs Identified	ng/ul	mg/sm^3	ppb
1A	Dinoseb spike	Unknown	25	N/A*	N/A
		Unknown	16	N/A	N/A
		Unknown	7	N/A	N/A
		Dichloro-iodo-benzene	12	N/A	N/A
2	Comb. blank w/ air staging	Unknown-phenyl	76	0.141	N/A
		Unknown	185	0.344	N/A
		Unknown	14	0.026	N/A
		Unknown-ester	6	0.011	N/A
		Dichloro-iodo-benzene	63	0.117	10.5
3	Comb. blank w/ air staging and reburning	Unknown-ester	43	0.160	N/A
		Dichloro-iodo-benzene	7	0.026	2.3
5	Dinoseb product w/ air staging	Unknown	13	0.141	N/A
		Unknown	10	0.109	N/A
		Styrene	8	0.087	20.5
		Dichloro-iodo-benzene	5	0.054	4.8
6	Dinoseb product w/ air staging and reburning	Unknown-ester	77	0.287	N/A
		Phthalate	21	0.078	N/A
		Dichloro-iodo-benzene	5	0.019	1.7

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*Not applicable.

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THE EFFECT OF FUEL NITROGEN ON NO_X EMISSIONS FROM A ROTARY-KILN INCINERATOR

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ABSTRACT

While thermal and fuel NO_X formation has been extensively studied for fossil fuel combustion, little information is available on NO_X formation from nitrogenous waste constituents. These wastes, usually destroyed in hazardous-waste incinerators, are prevalent and exist as solids (plastics, nylons) or liquids (dyes, process waste).

Results are presented from studies conducted with contaminated solids in a laboratory-scale, batch rotary-kiln simulator. Constituent parameters, i.e. type and percent fuel nitrogen, were studied at 1000 K. Sorbent was contaminated with a variety of compounds ranging in concentrations from 1.0% to 46.0% nitrogen by weight (for 681 g charge).

NO_X exhaust-gas concentrations ranged from 50 ppm to 100 ppm for a base run (no fuel nitrogen) to approximately 1,000 ppm for a nitrogenous waste. Results indicated that, at higher fuel-N concentrations, more NO_X was formed. Higher concentrations also resulted in reduced conversions of fuel nitrogen to NO_X. Conversion

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for different constituents, given the same concentration, varied; pyridine conversions were slightly higher than aniline, followed by ethylenediamine.

INTRODUCTION

Nitrogen oxides (NO and NO_2, commonly referred to as NO_x) can be formed from two sources:

1. nitrogen in the combustion air reacting with oxygen, defined as thermal NO_x, and
2. nitrogen in the fuel reacting with oxygen, or fuel NO_x.

While fuel NO_x formation has been studied extensively for fossil fuels, little information is available on the NO_x formation for nitrogenous waste constituents. The maximum fuel nitrogen content in fossil fuels is of the order of 2.0% by weight. Certain hazardous wastes can contain as high as 30% by weight nitrogen. Since hazardous-waste incinerators must be designed to meet environmental regulations, NO_x emissions generated from incineration of these high-level nitrogenous species must be understood.

The formation of thermal NO can be described by the Zeldovich mechanism (1); thermal NO formation is highly temperature dependent; however, below 1800 K, the mechanism is not favorable and formation is unlikely. Previous researchers have shown that if nitrogen is contained in the fuel, increased NO formation results. Pershing and Wendt (2) found that, in self-sustaining pulverized coal flames, fuel NO was the primary source of NO emissions. In addition, fuel-nitrogen oxidation was relatively insensitive to temperature, unlike thermal NO formation. In general, the research has shown that as fuel nitrogen content is increased, conversion to NO decreases. Conversion on the order of 50% can be possible for a fossil fuel containing 1% nitrogen. As oxygen levels are increased, a larger fraction of the fuel nitrogen converts to NO_x.

Unfortunately, the detailed mechanisms and kinetics involved in fuel-NO formation are not completely understood; however, the chemical kinetics of fuel-NO formation are closely related to that of prompt NO (3-8). Globally, the fuel-NO molecule is hypothesized to pyrolize or react to form an intermediate nitrogen containing species (HCN, N, HN, NH_2, or NH_3). The intermediate can then react with an oxygen containing molecule to form NO, or with NO to form another intermediate species (HCN, N, HN, NH_2, or NH_3) or to form N_2. Unlike thermal-NO, fuel-NO kinetics are not strongly temperature dependent.

Presently, most hazardous wastes are disposed by incineration or landfilling. With regulations regarding landfills becoming more stringent and companies having cradle-to-grave responsibility for wastes landfilled, permanent alternatives, such as incineration, must be explored. Little data has been gathered on nitrogen oxide emissions of high-level nitrogen-containing wastes in the hazardous-waste incinerator environment. These wastes, solids or liquids, are the result of spent plastics (nitriles) and nylons (amines), nitrogroups in dyes, and process-waste streams.

While several types of incinerators are currently commercially available, rotary-kilns represent a large portion of the systems used for hazardous-waste incineration. A kiln can be fed a variety of types of wastes - solids, liquids, or sludges - and the technology has been proven to destroy most organic wastes. For these reasons, future advances in rotary-kiln technology are expected (9) and a rotary kiln was chosen as the primary incinerator system in this study.

If the high nitrogen waste is burned as a liquid, then advanced, low-NO_x techniques developed for liquid fuels can often be utilized. England and co-workers (10,11) have shown that extremely low NO_x emission levels can be achieved by providing proper atomization, very high temperature, and sufficient residence time in an initial, fuel-rich portion of a two-stage combustion system. Figure 1 shows typical results from their studies at three different scales including an 8 million Btu/hr pilot-scale unit. These data indicate that NO_x emission levels of 60 ppm (0% O_2) were achieved with a fuel containing 0.6% nitrogen. Their data also indicated that, with an optimized system, the minimum NO_x was insensitive to fuel nitrogen content; liquid hydrocarbon wastes with 10% nitrogen would not be expected to produce more than 100 ppm NO_x under these conditions.

The situation with high nitrogen solid wastes is far more complex and was the focus of this study. The objectives of this research were to:

1. examine the conversion of fuel-nitrogen to NO_x in a waste material, in this study, a sorbent material contaminated with a nitrogen species (aniline, pyridine, or ethylenediamine) and toluene, and
2. determine the influence of operating and material parameters on the conversion. This paper discusses the influence of charging rate, nitrogen speciation and fuel-nitrogen content. Future studies will investigate the effects of excess oxygen and temperature.

EXPERIMENTAL APPARATUS AND PROCEDURE

To study the transient evolution of contaminants from solids, a rotary-kiln simulator has been constructed at the University of Utah. The rotary kiln simulator was designed to study the fate of a control volume of solids which would pass through a full-scale rotary kiln. In a full-scale kiln, a control volume of solids passes through the kiln for a defined residence time which is a function of kiln length, rotation speed, and slope of the kiln. In the simulator, as illustrated in Figure 2, a batch of solid is loaded into the simulator and combusted for a predetermined residence time. Time is exchanged for distance as the independent variable. A moveable burner can be positioned to vary the amount of flame that is directly exposed to the bed. By measuring the gas-phase component concentrations (O_2, CO, CO_2, NO_2, NO, and total hydrocarbons) and other parameters (temperature, rotation rate), as a function of time, it is possible to determine the fate of the hazardous species in a particular control volume.

A diagram of the rotary-kiln simulator is shown in Figure 3 and described in detail in Lemieux and Pershing (12). The simulator is rated at 73 kW and is constructed in three, refractory-lined sections - a burner section, a main section, and an exhaust section. The main section, where a charge is loaded, has an inner diameter of 0.61-m and is 0.61-m long. A moveable burner, equipped with axial and radial gas, is located in the burner section. The burner section and the main section rotate, while the exhaust section is stationary and connected to an afterburner system. The charge is loaded through the stationary exhaust section using a chute which extends into the main section.

Two windows allow an axial view of the flame and a direct view of the bed. Cooling coils are cast into the outside layer of refractory at the shell, and at the interface between the middle and the outside layers. The kiln is driven by a 1hp DC motor using a 200:1 worm reduction gear allowing rotational speeds between 0.2 and 2.0 rpm. Solid samples can be taken at any time during the experimental run. The afterburner system consists of two natural-gas fired burners placed in a rectangular combustion chamber opposing one another. Each burner is rated at 73 kW.

Gas-samples are taken from the flue section, the water in the gas is condensed, and the gas is then analyzed for CO_2 and CO, O_2, and NO_x, using the instruments listed in Table 1, and total hydrocarbons with Beckman THC analyzer. The analytical system is calibrated prior to each run as shown in Figure 4. A data acquisition system, Omegalog, is used to record the signals every 2.5 seconds for a total of 13 minutes. Data can then be directly transferred into a spreadsheet for reduction and analysis.

The test matrix for this study is shown in Table 2. A solid, sorbent material was contaminated with toluene and a nitrogen-containing waste (aniline, pyridine, ethylenediamine, or malononitrile) varying the weight percent nitrogen. The solid was then loaded into several cardboard containers which were then fed into the kiln. The total weight was 681.0 g with the exception of one experiment which was conducted using 340.5 g. This experiment and several experiments, using only the pure nitrogenous contaminant in various concentrations, were conducted to examine the effect of charge size on the conversions. The temperature was constant at 1000 K.

RESULTS

Base-Line Definition

Initially a series of experiments was conducted to define the impact of both the solid charge material and the nitrogen free toluene on the exhaust NO_x emissions. Figure 5, which summarizes these results, shows the time resolved NO_x emissions (normalized to 0% oxygen). The auxiliary natural gas flame produce approximately 50 ppm NO_x which results from thermal fixation of the atmospheric nitrogen associated with the combustion air. When 680 g of clean sorbent material in a cardboard container were charged (as indicated by the dotted line), the NO_x increased to approximately 80 ppm for about six minutes. This increase is probably attributable to a small amount of nitrogen contained in this commercial sorbent material and/or the container. Adding 35 g of toluene (nitrogen free) produced no additional NO_x.

These results indicate that, under the conditions of this study, thermal NO_x formation from the combustion of the hydrocarbon contaminants was not significant. The data further suggest that the incineration of non-nitrogen containing hydrocarbons in large rotary kiln systems may not produce major increases in exhaust NO_x emissions. Most kilns are operated with bulk temperatures well below the thermal NO_x formation thresh-hold of 1800°K and the intensity with which liberated hydrocarbons are burned may not be sufficient to produce the local temperatures and free radical concentrations required for significant NO_x formation.

Typical Time Resolved Data

Figure 6 shows typical time resolved NO_x profiles for separate, replicate experiments with 650g of sorbent which had been contaminated with 23.3 g of aniline and 11.7 g of toluene (to produce a 10wt% nitrogen contaminant). Approximately 100 seconds are required after the cardboard containers are loaded for the break-up of the containers and the initial heating of the solid. The hydrocarbons then began to vaporize and local ignition occurs.

This causes a rapid increase in the rate of vaporization and the NO_x emissions increase dramatically. The subsequent decrease, at approximately 300 seconds, occurs because the bulk of the nitrogen containing hydrocarbons have been evolved and burned. From 350 s to 500 s there is a small amount of NO_x formation, likely associated with the slow evolution of the final aniline molecules. Previous work with toluene and xylene has shown that the last 5 - 10% of the contaminant is more difficult to remove than the first 50%.

The time resolved, 10% aniline data are presented on a fractional conversion basis in Figure 7; exhaust oxygen concentrations are also shown. Initially, there is a relatively large amount of oxygen locally available to material being evolved from the bed. However, as the evolution rate increases and ignition occurs, the local oxygen is depleted. The overall conversion of the fuel nitrogen to NO_x is relatively low during this regime. Since this occurs at the point of peak mass evolution, this period of low conversion fortunately dominates the overall average conversion. During the final portions of the test (> 300 s), the local oxygen concentration again increases because the hydrocarbon evolution rate has greatly slowed; visible bulk combustion is no longer apparent. Nitrogen conversion increases during this period because of the increased oxygen availability.

Similar conversion characteristics would be expected in a full-scale rotary kiln where nitrogen containing solids were being charged in drums. During the period of peak burning rate, the instantaneous fuel nitrogen conversion would be lower than at the beginning or the end because the hydrocarbon combustion would tend to deplete the local oxygen.

Feeding Rate Effects

To investigate the effects of charging rate, an experiment was conducted in which the aniline, toluene, and sorbent material were all decreased by 50%. These results, shown in Figure 8, suggest that the integrated NO_x emissions are only weakly influenced by the kiln charging rate. The case with a smaller charge, ignited earlier and burned out faster as expected. The depression in the exhaust oxygen was approximately the same intensity but of shorter duration, suggesting similar average local oxygen concentrations through-out the period of nitrogen evolution. This resulted in an almost identical overall nitrogen conversion of 19.4 % relative to the base case nitrogen conversion of 18.7 %. The results are in good agreement with earlier fossil fuel studies which have indicated the importance of minimizing local oxygen availability.

Influence of Nitrogen Speciation

Aniline, pyridine, and ethylenediamine were all investigated to establish the influence of contaminant speciation. Figure 9 summarizes the overall results from a series of experiments where 680 g of total charge was added to the kiln. In these experiments only the pure nitrogen containing chemicals were used; toluene was not added to hold the hydrocarbon content of the sample constant. Rather, an equivalent amount of nitrogen was charged in each case (0.01 g of nitrogen per g of charge). These results show an apparent strong influence of chemical speciation on the overall conversion of the fuel nitrogen to NO_x.

To further investigate this somewhat surprising result, detailed experiments were conducted with all three compounds at various concentrations. Figure 10 summarizes typical time resolved emissions data for the aniline series; in these experiments the fuel nitrogen content in the hydrocarbon/contaminant mix (aniline plus toluene) was varied from 1% to 10% while holding the total hydrocarbon content constant at 35 g and the sorbent mass constant at 646 g. The time resolved behavior was similar for all three cases; both the peak and integrated NO_x emissions increased with increasing nitrogen content as expected.

Figure 11 summarizes all of the integrated conversion results obtained for the three different nitrogen-containing contaminants. These results are plotted as a function of the nitrogen content in the hydrocarbon contaminant; previous detailed studies on NO_x emissions from the combustion of liquid fuels, under excess air conditions (10) have indicated that weight percent nitrogen in the liquid phase is the primary correlating variable, given constant combustion conditions. Figure 11 indicates that the percentage of fuel nitrogen to converted NO_x decreases as the weight percent nitrogen increases. This result is consistent with the previous work of England (11) and kinetic theory. The conversion decreases with increasing nitrogen availability because the reactions forming NO are essentially first order with respect to available nitrogen species while the reactions forming N_2 are, of necessity, second order.

In contrast to the previously available data for liquid fuel combustion, the results shown in Figure 11 also suggest a secondary influence of nitrogen speciation. Figure 12 provides a detailed comparison of the conversion results obtained with the three compounds at a constant fuel nitrogen percentage (3%). Pyridine, where the nitrogen is contained in the aromatic ring, produced the highest relative conversion; ethylenediamine, where the nitrogen is present as an amine group in the alkane chain, resulted in the lowest nitrogen conversion. Further investigations are required to elucidate the mechanistic reason for this difference, but it is likely that the volatility of the nitrogen species, relative to the bulk hydrocarbon contaminant, is an important parameter.

CONCLUSIONS

The results of this study indicate that significant quantities of nitrogen oxides can be formed during the incineration of nitrogen containing solid waste. In this investigation, thermal NO_x formation was relatively insignificant; however, conversions of the nitrogen chemically bound in the organic contaminant to NO_x ranged from 2 to 46%, depending on the nitrogen speciation and combustion conditions.

Total NO_x emissions were related to the total nitrogen in the waste, the speciation of the nitrogen, and the nitrogen concentration in the hydrocarbon phase. NO_x emissions increased with increasing nitrogen content; however, the percentage conversion decreased in accordance with previous fossil fuel results. Nitrogen speciation was found to have a measurable but second order effect; conversions with pyridine were higher than with ethylenediamine.

For the conditions of this study, charging rate did not significantly influence either the percentage conversion of the chemical nitrogen, or the NO_x emissions per unit mass of contaminant. The experimental results suggest that the local oxygen concentration has a major influence on the instantaneous fuel nitrogen conversion, but additional studies are required to quantify the effects of excess oxygen and temperature.

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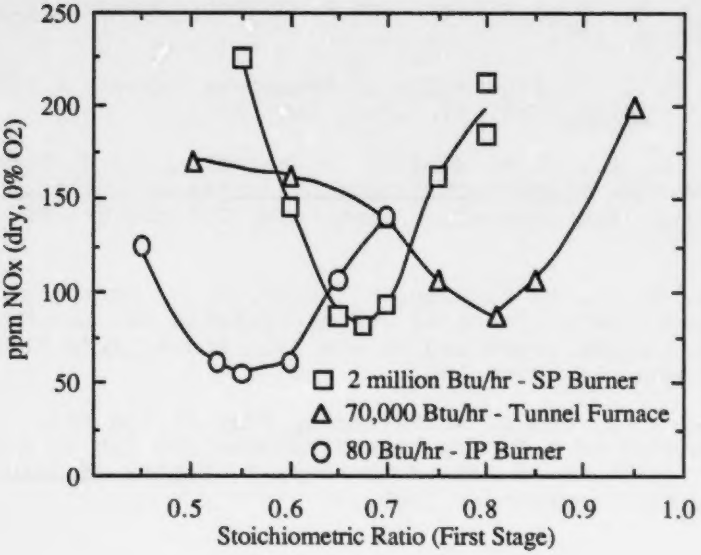

Figure 1. Influence of First-Stage Stoichiometry on NOx (Bench-scale and Pilot-Scale) from England (11)

- Control Volume Follows Batch of Solid Through Kiln

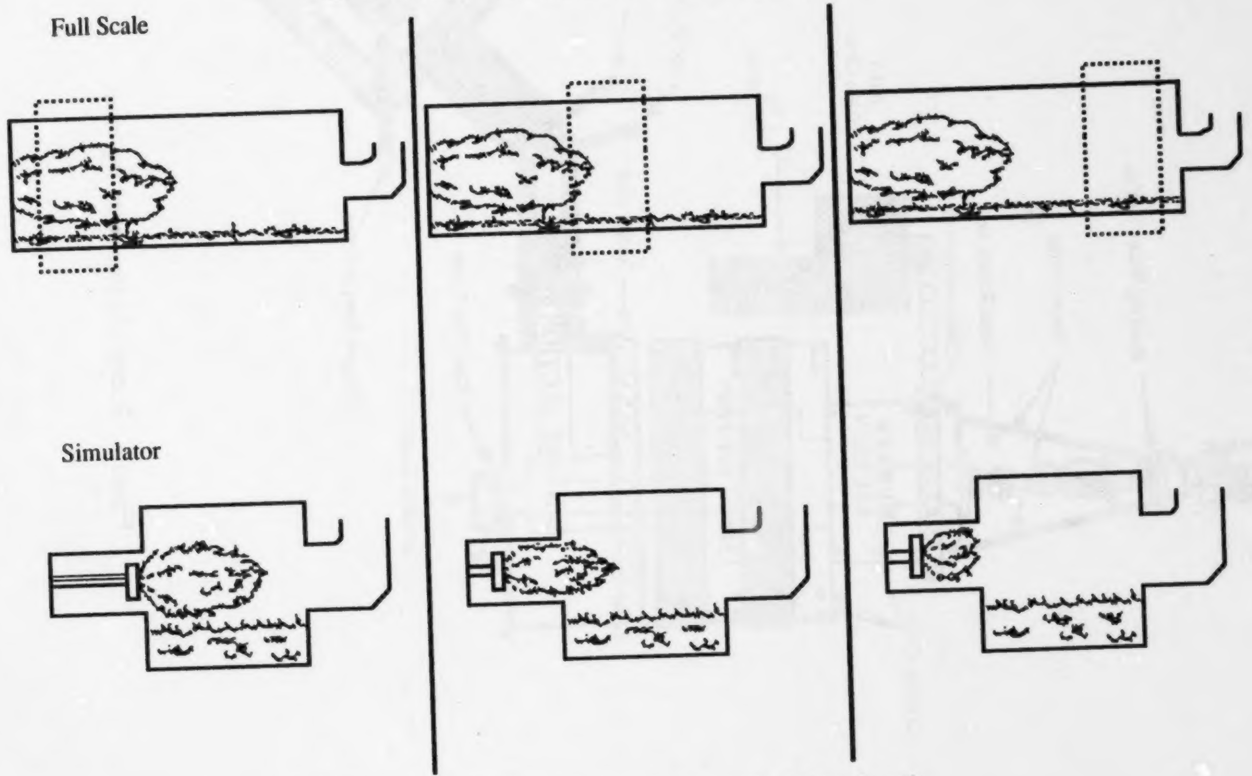
Full Scale
Simulator

Figure 2. Lab-scale rotary-kiln simulation of a full-scale unit.

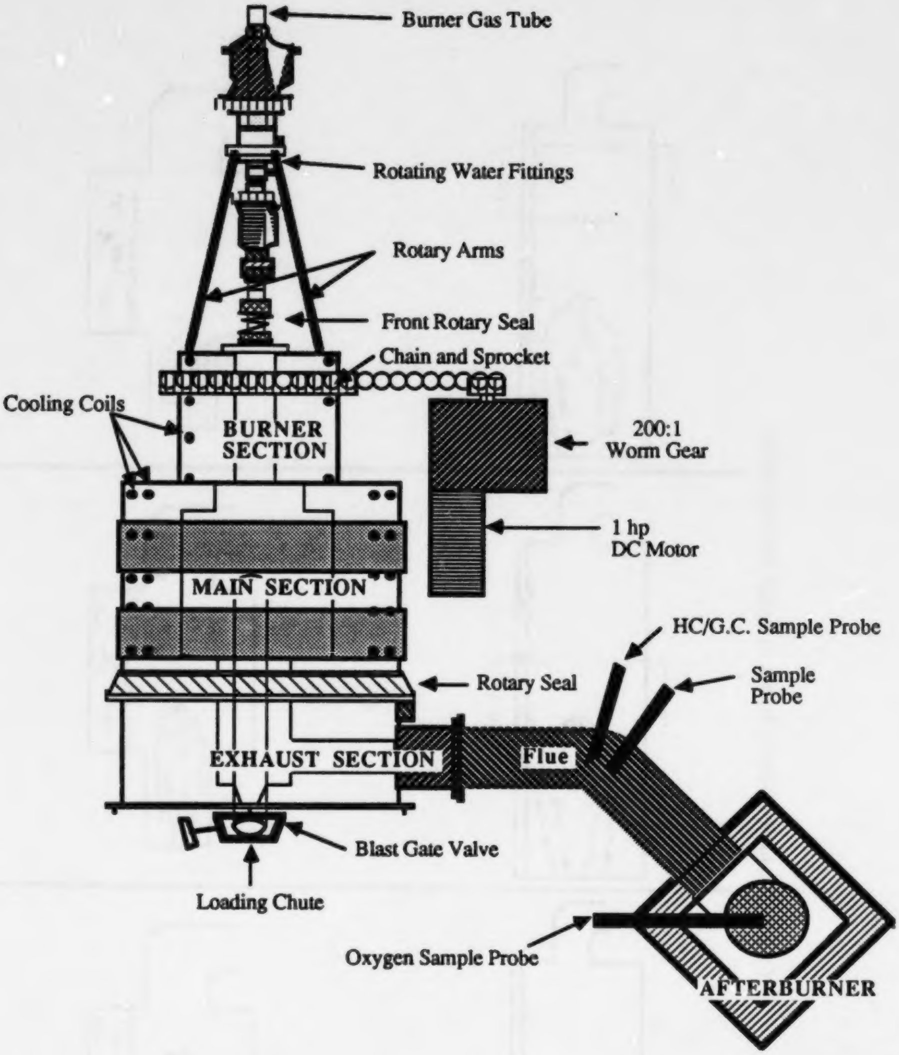
Burner Gas Tube
Rotating Water Fittings
Rotary Arms
Front Rotary Seal
Chain and Sprocket
Cooling Coils
BURNER SECTION
200:1 Worm Gear
1 hp DC Motor
MAIN SECTION
HC/G.C. Sample Probe
Sample Probe
Rotary Seal
EXHAUST SECTION
Flue
Blast Gate Valve
Loading Chute
Oxygen Sample Probe
AFTERBURNER

Figure 3. Rotary-kiln simulator: top view.

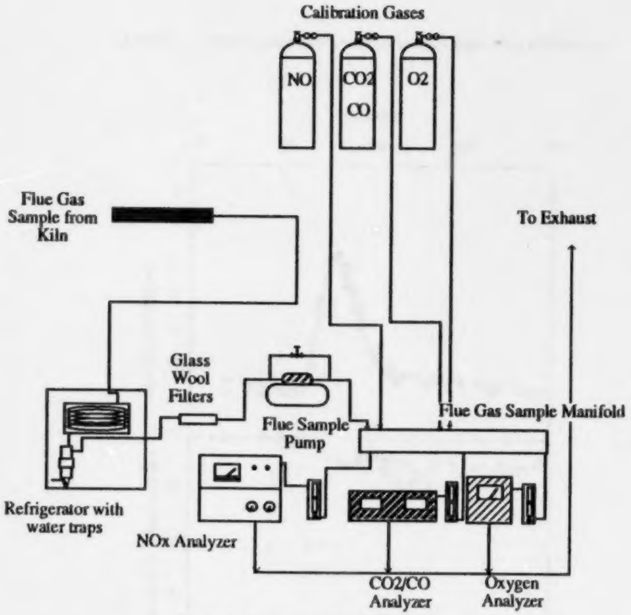
Calibration Gases
NO
CO2
CO
O2
Flue Gas Sample from Kiln
To Exhaust
Glass Wool Filters
Flue Sample Pump
Flue Gas Sample Manifold
Refrigerator with water traps
NOx Analyzer
CO2/CO Analyzer
Oxygen Analyzer

Figure 4. Sample Analysis System

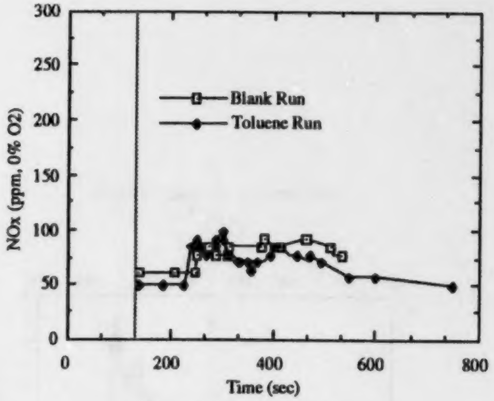

Figure 5. Baseline NOx Formation
(dotted line indicates point of bed charging)

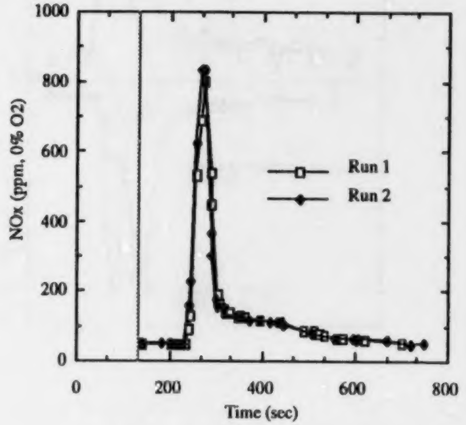

Figure 6. Typical, Time-Resolved NOx Profile

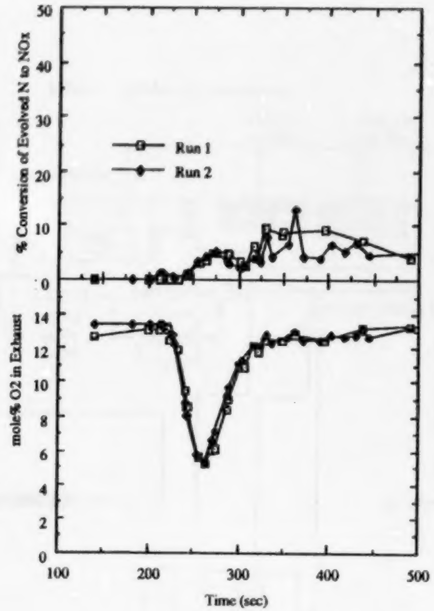

Figure 7. Typical Time-Resolved Conversion Data and Oxygen Data

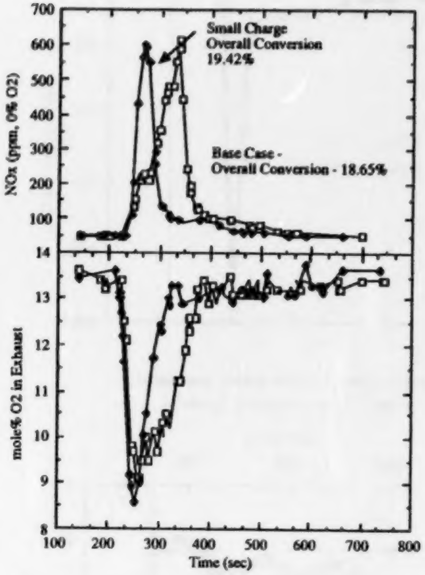

Figure 8. Influence of Charge Size

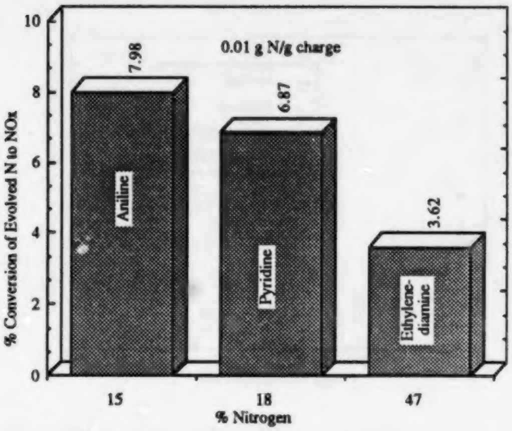

Figure 9. Influence of Compound Type and N Concentration

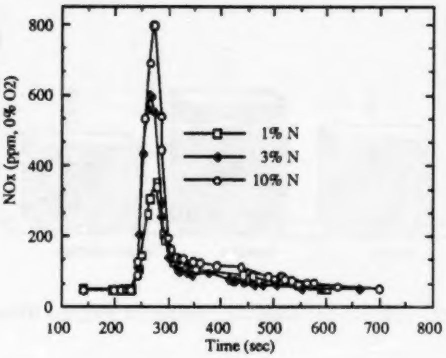

Figure 10. Comparison of Nitrogen in Fuel

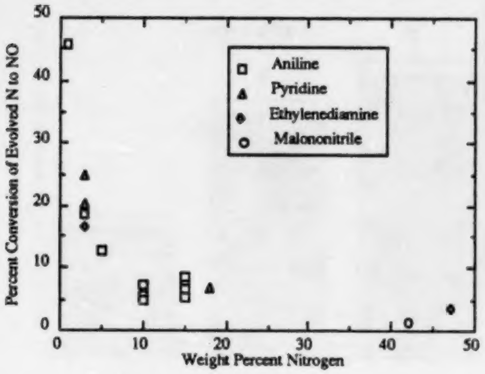

Figure 11. Effect of Nitrogen in Fuel on Nitrogen Conversion to NO

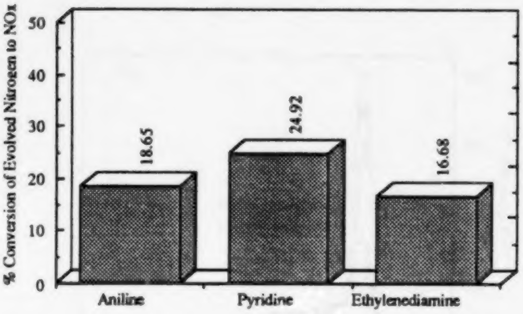

Figure 12. Influence of Compound Type for 3.0 Weight% Nitrogen

Table 1

Analytical Instruments

Instrument	Range	Analog Voltage Output
Anarad Model AR-600 Dual Gas Analyzer (NDIR)	CO_2 Ranges 0 - 6% 0 - 30%	0 - 100 mV
	CO Ranges 0 - 1% 0 - 10%	0 - 100 mV
Beckman Model 755 Paramagnetic Oxygen Analyzer	Four range selections 0 - 5% 0 - 10% 0 - 25% 0 - 50%	0 - 100 mV
ThermoElectric Series 10 Chemiluminescent NO - NO_2 - NOx	Eight range selections 0 - 2.5 ppm 0 - 10 ppm 0 - 25 ppm 0 - 100 ppm 0 - 250 ppm 0 - 1000 ppm 0 - 2500 ppm 0 - 10000 ppm	0 - 10 mV
Beckman Model 400 Total Hydrocarbon Analyzer (Flame Ionization Detector)	Four range selections 0 - 10 ppm 0 - 100 ppm 0 - 1000 ppm 0 - 10000 ppm	0 - 100 mV

Table 2

Test Matrix

Constituent	g Constituent	g Toluene	g Sorbent	wt% Nitrogen in the Total Hydrocarbon Mixture
none	0.0 (a)	0.0	681.0	0.0
none	0.0	35.0	646.0	0.0
Aniline	2.3	32.7	646.0	1.0
	3.5	14.0	323.0	3.0
	7.0	28.0	646.0	3.0
	11.6	23.4	646.0	5.0
	23.3 (a)	11.7	646.0	10.0
	22.6	0.0	658.4	15.0
	45.3	0.0	635.7	15.0
	79.2	0.0	601.8	15.0
	113.1	0.0	567.9	15.0
Pyridine	8.5	41.5	631.0	3.0
	5.9	29.1	646.0	3.0
	38.4	0.0	642.6	18.0
	115.3 (b)	0.0	565.7	18.0
Malononitrile	56.2	0.0	624.8	42.0
Ethylenediamine	2.3	32.7	646.0	3.0
	29.1	0.0	651.9	47.0

Notes: (a) 3 replicate runs

(b) 2 replicate runs

Appendix A

EPRI/EPA Symposium on Stationary Combustion NOx Control

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